Performance Test Report Unit 1 Vol 1 Turbine Cycle

# INTERMOUNTAIN GENERATING STATION

# PERFORMANCE TEST REPORT

## UNIT 2
## VOLUME 1
## TURBINE CYCLE

IPP

INTERMOUNTAIN POWER PROJECT

BLACK & VEATCH/engineers-architects

1987

# INTERMOUNTAIN GENERATING STATION

# PERFORMANCE TEST REPORT

## UNIT 2
## VOLUME 1
## TURBINE CYCLE

IPP
INTERMOUNTAIN POWER PROJECT

BLACK & VEATCH/engineers-architects
1987

CONTENTS

CONTENTS (Continued)

LIST OF TABLES

CONTENTS (Continued)

LIST OF FIGURES

# 1.0 INTRODUCTION

This report describes efficiency testing of power plant equipment for Intermountain Power Project Unit 2. It covers performance results, sample calculations, and data related to the eight test runs. The tests were conducted from May 11, 1987 through May 16, 1987. The unit was first synchronized in February 1987. The following groups of personnel assisted in and observed the tests.

Black & Veatch

General Electric

Intermountain Power Project Startup

Intermountain Power Service Corporation

Los Angeles Department of Water and Power

These tests were conducted to evaluate overall generating station and equipment performance. General Electric test data were used in determining the net turbine heat rate, condenser, feedwater heater, and boiler feed pump performance.

In addition to determing acceptability of equipment performance, the tests provide IPSC with bench mark data. Subsequent periodic tests on the unit can be compared with this bench mark data to reveal equipment wear or deterioration of performance from other causes.

# 2.0 SUMMARY AND CONCLUSIONS

## 2.1 TURBINE GENERATOR

The turbine-generator heat rate at 820 MW was determined by straight line interpolation between the corrected test heat rates for the third and fourth valve point tests and subtracting the differential heat rate between the straight line and design curve, in accordance with the contract. This resulted in a heat rate of 7,786 Btu/kWh, by the customer definition (1 percent condensate makeup), and is 0.5 percent better than the manufacturer's guarantee heat rate of 7,826 Btu/kWh. (Heat rates include power to booster boiler feed pumps.)

## 2.2 BOILER FEED PUMP TURBINES

The boiler feed pump turbines were not set at a specific valve point. This prevents finding corrections to calculate boiler feed pump turbine performance.

## 2.3 BALANCE OF PLANT

Data obtained from the above tests, along with concurrent station instrument data, were used to evaluate the performance of various equipment in the plant cycle, and to determine what equipment needs additional testing. The results are summarized as follows.

### 2.3.1 Surface Condenser

While the hood pressures were excessive in earlier tests, the performance factors of heat transfer coefficient and cleanliness were deficient only in Hood B (IP Condenser 1B).

Higher than expected condenser hood pressures indicated air infiltration into the condenser. Leaks were located and eliminated or reduced for the final two turbine tests. Test 9, when compared with Test 3, exhibits substantially reduced pressures in Condenser Hoods A and B (HP Condenser 1A and IP Condenser 1B). It is most likely that the elimination of air infiltration will produce expected condenser performance.

### 2.3.2 Feedwater Heaters

All of the feedwater heaters with the exception of LP Heater 1C, which had high shell pressure readings, had better than guaranteed subcooler approach temperature differentials, and terminal temperature differentials closely comparable to guarantees.

### 2.3.3 Main Boiler Feed Pumps

The efficiencies of Boiler Feed Pumps 1A and 1B were 80.55 and 83.18 percent, respectively, as determined from the torque monitoring system data. Boiler Feed Pump 1B discharge pressure data was taken from the Information Computer. While it would appear that the guaranteed pump efficiency of 87 percent was not met, the test speeds for the pumps were significantly different from the rated speed. Further testing at the rated pump speed is required for accurate comparison.

# 3.0 TEST RESULTS

## 3.1 GENERAL

General Electric test data and Information Computer data, when required, were used in the performance calculations. Test cycle heat balances, Figures 3-1 through 3-8, are based on heat balance calculations around the high-pressure heaters and deaerator, using a calibrated condensate flow section to determine boiler feedwater flow and subsequently main steam and reheat steam flows.

## 3.2 TURBINE GENERATOR

The measure of the turbine-generator's performance is the net turbine heat rate. The turbine-generator performance was guaranteed on a "customer definition" heat rate basis. The customer heat rate was calculated by dividing the corrected heat input by the corrected generator output.

Table 3-1 is a summary of the customer definition turbine heat rates and corrected loads. Figure 3-9 shows the turbine heat rates determined from the tests and manufacturer's predicted heat rates. The test heat rates were corrected using ASME PTC 6.0 Group I and Group II corrections. The Group II correction curves are included in Section 6.0 of this report.

The test net heat rate is calculated by dividing the total heat input by the net generation. Figure 3-10 is a graphical representation of the test net heat rate versus net generation. There was no attempt to draw a curve through these data points due to data scatter. Lower heat rates are indicative of higher steam temperatures and pressures and lower condenser hood pressures. A summary of the test net heat rates is shown in Table 3-2.

Turbine stage efficiencies were determined by dividing the available energy in the steam by the isentropic expansion heat content of the steam. Table 3-3 shows a summary of the stage efficiencies for each test.

A Willins Curve, throttle flow versus gross generation, is shown on Figure 3-11. Table 3-4 shows a summary of the throttle flows and gross generator output.

## 3.3 CONDENSER

The condenser heat transfer coefficient is calculated by dividing the heat rejected from the condensate by the area of the surface condenser and the log mean temperature difference of the circulating water. This value is then corrected for circulating water inlet temperature. The cleanliness factor is found by comparing the actual corrected heat transfer coefficient with a manufacturer-defined minimum cleanliness heat transfer coefficient.

The heat transfer coefficient and cleanliness factor for each condenser hood were calculated for the VWO tests and are shown on Table 3-5 as a comparative tabulation of condenser performance.

## 3.4 FEEDWATER HEATERS

Heater performance is generally measured by the terminal difference and subcooler approach temperatures. Graphical representations of the heater performances which illustrate terminal difference and subcooler approach temperatures varying with load are shown in Figures 3-12 through 3-22.

Table 3-6 shows the comparative closed feedwater heater performance. A summary of the terminal difference and subcooler approach temperatures is shown in Table 3-7.

## 3.5 BOILER FEED PUMPS

Boiler feed pump efficiency is calculated by multiplying the developed head by the volumetric flow and specific gravity of the water pumped and dividing by the horsepower input and appropriate conversion factors. Relative performance is calculated by dividing the corrected developed head by the expected developed head. Expected developed head is a function of corrected volumetric flow. Information Computer pump discharge pressure for Boiler Feed Pump 1B was used in the calculations.

Table 3-8 is a comparative tabulation of boiler feed pump performance. Table 3-9 provides a summary of the pump efficiencies and relative performance for the tests.

### 3.6 FEEDWATER FLOW NOZZLE VERSUS CONDENSATE FLOW NOZZLE

ASME PTC 6.1 provides an alternative testing procedure to determine turbine heat rate. Instead of measuring the condensate flow and calculating the feedwater flow, a flow element in the feedwater line after the final feedwater heater is used to directly compute the feedwater flow. It has been shown that this is an acceptable, less expensive method, due to fewer, less precise measurements.

Test heat rates for the full ASME test and for the feedwater flow nozzle measurements were calculated and are shown in Table 3-10. For most of the tests, the difference between the heat rates determined from the feedwater flow nozzle as compared to the heat rates determined from the condensate flow nozzle are within the 1/3 percent uncertainty expected in PTC 6.1.

TABLE 3-1. ONE PERCENT MAKEUP CORRECTED HEAT RATES

| | Corrected Heat Rate, Btu/kWh | Corrected Load, kW |
|---|---|---|
| VWO | 7779.3 | 873,212 |
| 3rd VP | 7795.8 | 794,888 |
| 2nd VP | 7923.2 | 598,149 |

Interpolated Heat Rate
at 820 MW = 7,786 Btu/kWh

Guaranteed Heat Rate
at 820 MW = 7,826 Btu/kWh

Note: Includes booster boiler feed pump power.

TABLE 3-2. TEST NET HEAT RATE VERSUS NET LOAD

| Test | Test HR, Btu/kWh | Net Load, kW Measured |
|---|---|---|
| 8 | 8,254 | 848,120 |
| 4 | 8,384 | 809,939 |
| 6 | 8,330 | 812,736 |
| 5 | 8,382 | 738,619 |
| 7 | 8,392 | 728,514 |
| 10 | 8,169 | 752,881 |
| 3 | 8,562 | 552,196 |
| 9 | 8,277 | 563,773 |

TABLE 3-3. TURBINE EFFICIENCY

| Test | High Pressure, Percent | Intermediate Pressure, Percent | Low Pressure (ELEP), Percent |
|---|---|---|---|
| 8 | 88.02 | 92.71 | 93.21 |
| 4 | 88.19 | 92.80 | 92.61 |
| 6 | 88.33 | 92.51 | 93.06 |
| 5 | 86.49 | 92.58 | 92.62 |
| 7 | 86.55 | 92.71 | 92.73 |
| 10 | 86.47 | 92.59 | 92.79 |
| 3 | 81.78 | 93.78 | 92.72 |
| 9 | 81.68 | 92.36 | 93.76 |

TABLE 3-4. THROTTLE FLOW VERSUS GROSS GENERATION

| Test | Gross Generation, kW | Throttle Flow, lb/h |
|---|---|---|
| 8 | 898,360 | 6,495,805 |
| 4 | 859,949 | 6,220,846 |
| 6 | 860,776 | 6,221,229 |
| 5 | 785,541 | 5,568,489 |
| 7 | 775,094 | 5,478,699 |
| 10 | 789,291 | 5,473,079 |
| 3 | 592,046 | 4,046,000 |
| 9 | 599,733 | 3,976,634 |

TABLE 3-5. COMPARATIVE CONDENSER PERFORMANCE

| | Test* | Guarantee |
|---|---|---|
| Pressure (in. Hg) | | |
| Condenser 1A | 4.31 | 3.36 |
| Condenser 1B | 4.15 | 2.80 |
| Condenser 1C | 2.65 | 2.34 |
| Heat Transfer Coefficient (Btu/h-ft$^2$-F) | | |
| Condenser 1A | 576.31 | 558.8 |
| Condenser 1B | 391.61 | 539.3 |
| Condenser 1C | 607.82 | 539.3 |
| Cleanliness Factor (percent) | | |
| Condenser 1A | 95.55 | 85 |
| Condenser 1B | 64.81 | 85 |
| Condenser 1C | 100.59 | 85 |

*VWO

TABLE 3-6. COMPARATIVE FEEDWATER HEATER PERFORMANCE

LOW-PRESSURE HEATERS

| | Design | Test |
|---|---|---|
| **Heaters 1A, 1B, and 1C** | | |
| Condensate Flow, lb/h | 5,254,771 | 4,526,700 |
| Shell Pressure, psia | 4.51 | 4.86* |
| Steam to Heater, lb/h | 169,144 | 120,335 |
| Enthalpy of Steam, Btu/lb | 1,100.9 | 1,090 |
| Terminal Difference, F | 2.0 | 0.29* |
| Subcooler Approach, F | 5.0 | 5.26 |
| Subcooler Flow, lb/h | 920,818 | 564,152 |

*Does not include Heater 1C.

| | Design | Test |
|---|---|---|
| **Heater 2** | | |
| Condensate Flow, lb/h | 5,254,771 | 4,526,700 |
| Shell Pressure, psia | 10.7 | 11.07 |
| Steam to Heater, lb/h | 178,238 | 142,336 |
| Enthalpy of Steam, Btu/lb | 1,142.5 | 1,163.0 |
| Terminal Difference, F | 2.0 | 2.15 |
| Subcooler Approach, F | 10 | 7.87 |
| Subcooler Flow, lb/h | 573,462 | 421,816 |
| **Heater 3** | | |
| Condensate Flow, lb/h | 6,127,017 | 4,526,700 |
| Shell Pressure, psia | 37.7 | 38.05 |
| Steam to Heater, lb/h | 378,723 | 279,958 |
| Enthalpy of Steam, Btu/lb | 1,236.2 | 1,244.9 |
| Terminal Difference, F | 2.0 | -0.03 |
| Subcooler Approach, F | 10 | 8.74 |
| Subcooler Flow, lb/h | 194,754 | 141,522 |

TABLE 3-6 (Continued). COMPARATIVE FEEDWATER HEATER PERFORMANCE

LOW-PRESSURE HEATERS (Continued)

| | Design | Test |
|---|---|---|
| Heater 4 | | |
| Condensate Flow, lb/h | 6,127,017 | 4,526,700 |
| Shell Pressure, psia | 63.2 | 63.5 |
| Steam to Heater, lb/h | 194,754 | 141,859 |
| Enthalpy of Steam, Btu/lb | 1,282.3 | 1,291.6 |
| Terminal Difference, F | 2.0 | -0.23 |
| Subcooler Approach, F | 10 | 4.78 |
| Subcooler Flow, lb/h | -- | -- |

HIGH-PRESSURE HEATERS

| | Design | Test |
|---|---|---|
| Heaters 6A and 6B | | |
| Feedwater Flow, lb/h | 6,513,490 | 6,221,038 |
| Shell Pressure, psia | 230.6 | 230.1 |
| Steam to Heater, lb/h | 239,944 | 234,886 |
| Enthalpy of Steam, Btu/lb | 1,419.8 | 1,426.5 |
| Terminal Difference, F | -2.0 | -1.33 |
| Subcooler Approach, F | 10 | 7.79 |
| Subcooler Flow, lb/h | 1,203,812 | 1,134,309 |
| Heaters 7A and 7B | | |
| Feedwater Flow, lb/h | 6,513,490 | 6,221,038 |
| Shell Pressure, psia | 584.3 | 557.5 |
| Steam to Heater, lb/h | 610,344 | 550,173 |
| Enthalpy of Steam, Btu/lb | 1,306.6 | 1,305.9 |
| Terminal Difference, F | -1.0 | -0.60 |
| Subcooler Approach, F | 10 | 9.26 |
| Subcooler Flow, lb/h | 593,470 | 584,136 |

TABLE 3-6 (Continued). COMPARATIVE FEEDWATER HEATER PERFORMANCE

HIGH-PRESSURE HEATERS (Continued)

| | Design | Test |
|---|---|---|
| Heaters 8A and 8B | | |
| Feedwater Flow, lb/h | 6,513,490 | 6,221,038 |
| Shell Pressure, psia | 1,061 | 1,063.8 |
| Steam to Heater, lb/h | 593,470 | 584,136 |
| Enthalpy of Steam, Btu/lb | 1,369.2 | 1,379.2 |
| Terminal Difference, F | -2.0 | -0.20 |
| Subcooler Approach, F | 10 | 7.22 |
| Subcooler Flow, lb/h | -- | -- |

TABLE 3-7. FEEDWATER HEATER TEST RESULTS

LOW-PRESSURE HEATERS

| Test | Heater 1A, TD | Heater 1B, TD | Heater 1C, TD | Heater 1, SA |
|---|---|---|---|---|
| 8 | 0.36 | 0.36 | 7.03 | 6.23 |
| 4 | 0.30 | 0.31 | 3.33 | 5.07 |
| 6 | 0.29 | 0.25 | 5.35 | 5.45 |
| 5 | 0.30 | 0.21 | 5.58 | 4.76 |
| 7 | 0.38 | 0.27 | 8.19 | 4.49 |
| 10 | 0.35 | 0.25 | 9.81 | 5.68 |
| 3 | 0.63 | 0.26 | 5.51 | 2.17 |
| 9 | 0.40 | 0.23 | 15.83 | 3.26 |

| | Heater 2 | | Heater 3 | | Heater 4 | |
|---|---|---|---|---|---|---|
| Test | TD | SA | TD | SA | TD | SA |
| 8 | 2.27 | 8.18 | 0.10 | 8.93 | 0.02 | 5.03 |
| 4 | 2.16 | 7.83 | -0.05 | 8.73 | -0.17 | 4.76 |
| 6 | 2.13 | 7.90 | -0.01 | 8.74 | -0.28 | 4.79 |
| 5 | 1.95 | 7.45 | -0.48 | 8.26 | -0.49 | 4.11 |
| 7 | 1.94 | 7.31 | -0.46 | 8.15 | -0.55 | 4.09 |
| 10 | 2.01 | 7.57 | -0.22 | 8.35 | -0.48 | 4.22 |
| 3 | 1.78 | -4.64* | -1.08 | 6.78 | -0.94 | 3.12 |
| 9 | 1.82 | -6.16* | -1.12 | 6.81 | -1.08 | 3.13 |

*Heater 2 alternate drains to condenser.

TABLE 3-7 (Continued). FEEDWATER HEATER TEST RESULTS

HIGH-PRESSURE HEATERS

| | Heater 6A | | Heater 6B | | Heater 7A | | Heater 7B | |
|---|---|---|---|---|---|---|---|---|
| Test | TD | SA | TD | SA | TD | SA | TD | SA |
| 8 | -0.87 | 7.75 | -0.72 | 8.40 | -0.16 | 9.72 | 0.86 | 8.60 |
| 4 | -1.45 | 7.54 | -1.30 | 8.08 | -1.04 | 9.35 | -0.24 | 10.17 |
| 6 | -1.33 | 7.51 | -1.22 | 8.03 | -0.98 | 9.25 | -0.15 | 8.26 |
| 5 | -2.29 | 6.78 | -2.08 | 7.28 | -1.86 | 8.26 | -1.17 | 7.42 |
| 7 | -2.39 | 6.75 | -2.15 | 6.99 | -2.05 | 8.16 | -1.33 | 7.30 |
| 10 | -3.10 | 6.67 | -2.60 | 7.19 | -2.11 | 8.23 | -1.17 | 6.85 |
| 3 | -3.62 | 5.45 | -3.97 | 5.53 | -2.24 | 6.31 | -2.37 | 5.66 |
| 9 | -3.82 | 5.02 | -3.86 | 5.63 | -2.99 | 6.11 | -2.41 | 5.47 |

| | Heater 8A | | Heater 8B | |
|---|---|---|---|---|
| Test | TD | SA | TD | SA |
| 8 | 1.78 | 7.63 | 0.64 | 7.67 |
| 4 | 0.35 | 7.23 | -0.81 | 7.23 |
| 6 | 0.42 | 7.18 | -0.74 | 7.22 |
| 5 | -1.47 | 6.27 | -2.74 | 6.18 |
| 7 | -1.69 | 6.17 | -2.73 | 5.75 |
| 10 | -1.81 | 6.23 | -3.01 | 6.19 |
| 3 | -3.99 | 5.20 | -5.16 | 4.28 |
| 9 | -4.13 | 4.42 | -5.25 | 4.12 |

TABLE 3-8. COMPARATIVE BOILER FEED PUMP PERFORMANCE

| | Guarantee | Boiler Feed Pump 1A | Boiler Feed Pump 1B |
|---|---|---|---|
| Capacity, gpm | 7,700 | 7,153 | 7,728 |
| Total Head, feet | 8,000 | 7,816 | 7,715 |
| Efficiency, percent | 87.0 | 80.55 | 83.18 |
| Brake Horsepower, bhp | 15,562 | 12,351 | 13,186 |
| Pump Speed, rpm | 5,750 | 5,295 | 5,353 |
| Relative Performance | 1.0 | 0.774 | 0.832 |

Note: Boiler Feed Pump 1B results derived from station data pump discharge pressure.

TABLE 3-9. TURBINE DRIVEN BOILER FEED PUMPS

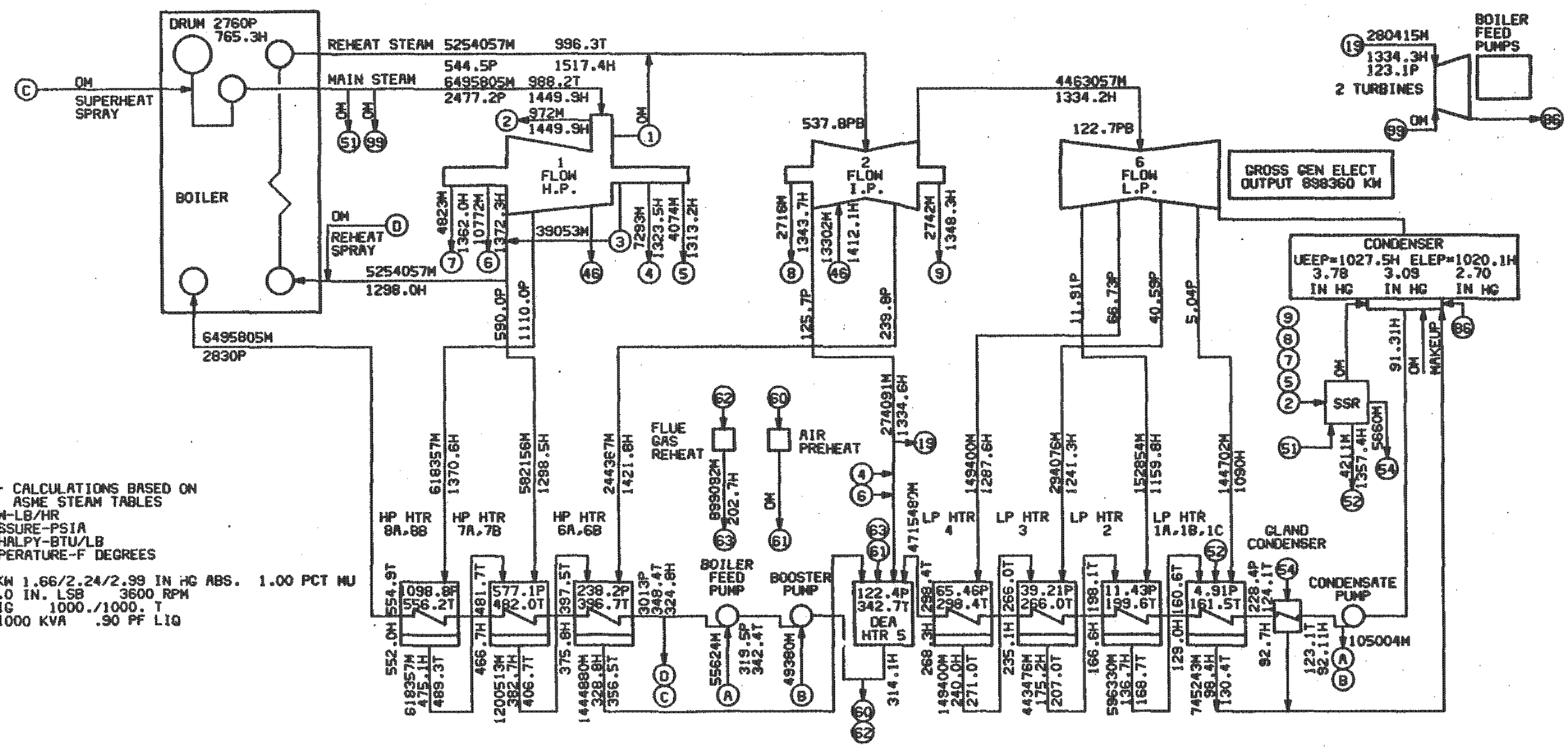
| Test | Boiler Feed Pump 1A Efficiency, Percent | Boiler Feed Pump 1A Relative Performance | Boiler Feed Pump 1B Efficiency, Percent | Boiler Feed Pump 1B Relative Performance |
|---|---|---|---|---|
| 8 | 80.15 | 0.817 | 82.61 | 0.876 |
| 4 | 80.58 | 0.774 | 83.18 | 0.831 |
| 6 | 80.51 | 0.774 | 83.17 | 0.832 |
| 5 | 82.15 | 0.715 | 84.47 | 0.751 |
| 7 | 81.77 | 0.692 | 84.27 | 0.726 |
| 10 | 81.06 | 0.692 | 82.71 | 0.728 |
| 3 | 80.43 | 0.616 | 88.44 | 0.644 |
| 9 | 81.29 | 0.606 | 88.70 | 0.637 |

TABLE 3-10. TEST HEAT RATE

| Test | Feedwater Nozzle Btu/kWh | Condensate Nozzle Btu/kWh | Error, Percent |
|---|---|---|---|
| 8 | 7,796 | 7,792 | 0.05 |
| 4 | 7,905 | 7,897 | 0.10 |
| 6 | 7,881 | 7,865 | 0.20 |
| 5 | 7,877 | 7,877 | 0.00 |
| 7 | 7,889 | 7,887 | 0.03 |
| 10 | 7,665 | 7,792 | 1.63 |
| 3 | 8,024 | 7,985 | 0.49 |
| 9 | 7,783 | 7,781 | 0.03 |

FIGURE 3-1

ARRANGEMENT IS SCHEMATIC ONLY




LEGEND - CALCULATIONS BASED ON
ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

$$\text{TEST HEAT RATE} = \frac{6495805(1449.9-552.0)+6495805(1.45)+4820484(92.1-91.3)+5254057(1517.4-1298.0)+6496(765.3-552.0)}{898360\text{KW}} = 7792 \frac{\text{BTU}}{\text{KW HR}}$$

CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE $= 7723 \frac{\text{BTU}}{\text{KW HR}}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 2
TEST 8 - VWO 5% OVERPRESSURE HEAT BALANCE

IP14_007360

ARRANGEMENT IS SCHEMATIC ONLY

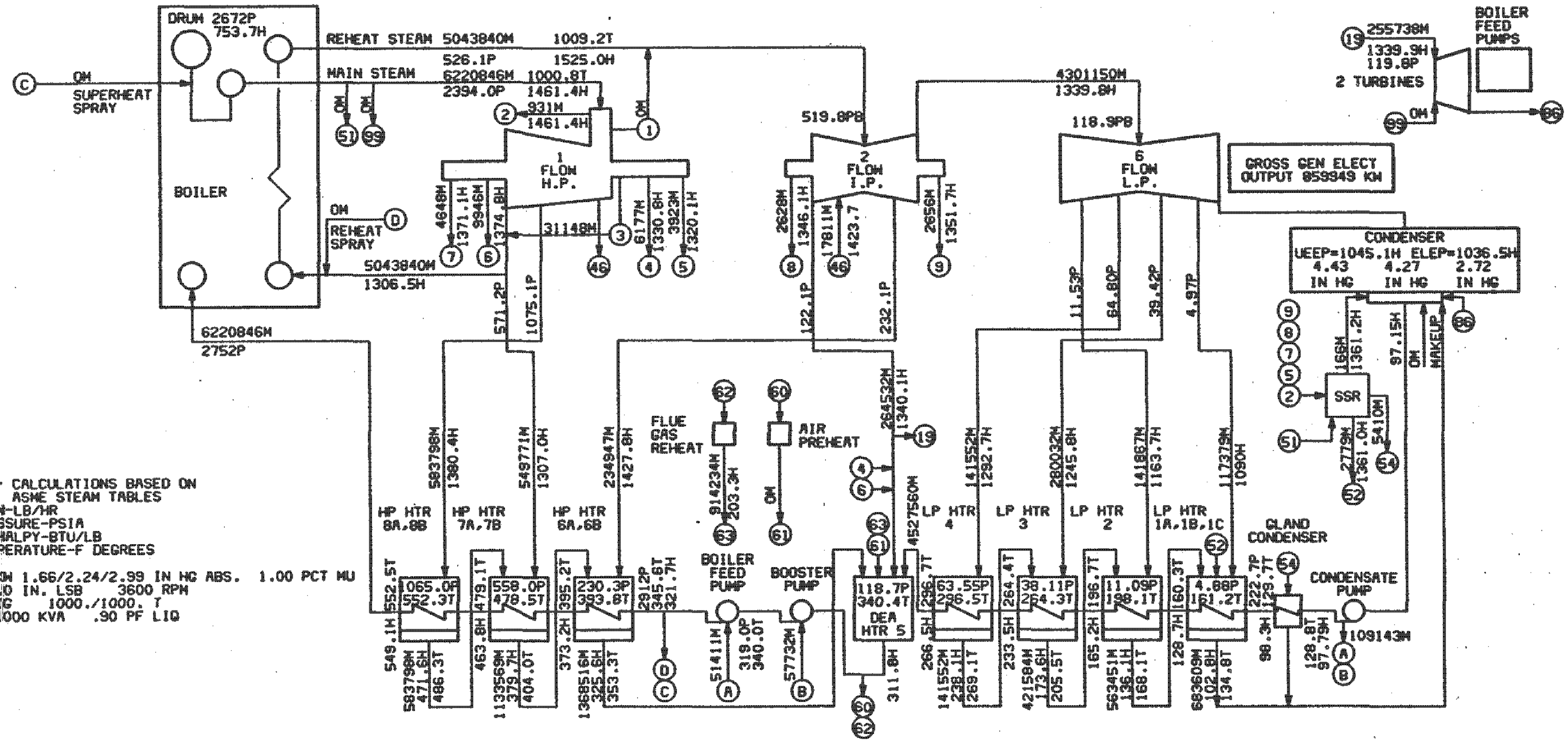



FIGURE 3-2

LEGEND - CALCULATIONS BASED ON
ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

$$\text{TEST HEAT RATE} = \frac{6220846(1461.4-549.1)+6220846(1.45)+4636703(97.8-97.2)+5043840(1525.0-1306.5)+6220(753.7-549.1)}{859949\text{KW}} = 7897 \frac{\text{BTU}}{\text{KW HR}}$$

CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE $= 7785 \frac{\text{BTU}}{\text{KW HR}}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 2
TEST 4 - VWO HEAT BALANCE

IP14_0073361

ARRANGEMENT IS SCHEMATIC ONLY

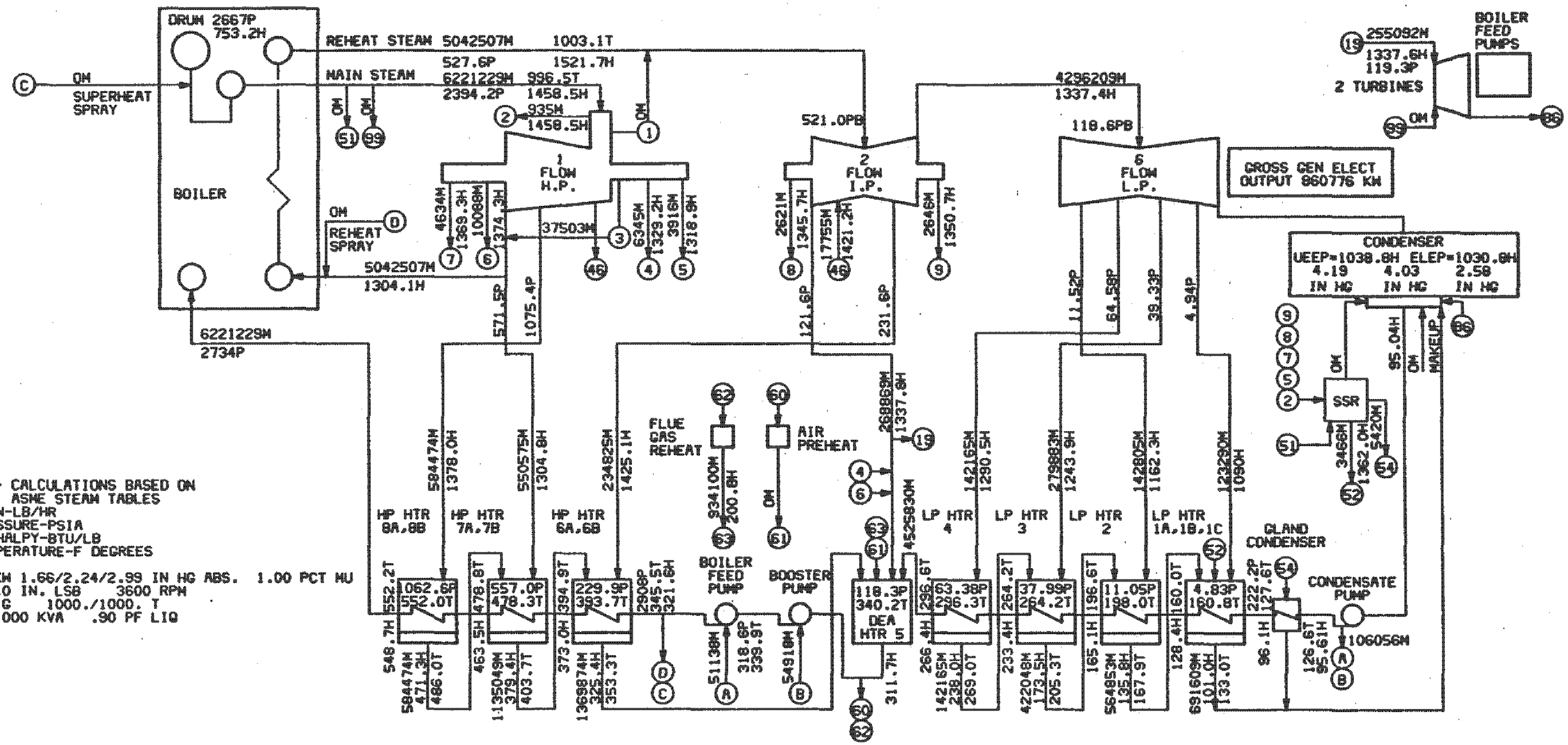



FIGURE 3-3

LEGEND - CALCULATIONS BASED ON
ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

TEST HEAT RATE $= \dfrac{6221229(1458.5-548.7)+6221229(1.45)+4631886(95.6-95.0)+5042507(1521.7-1304.1)+6221(753.2-548.7)}{860776KW} = 7865 \dfrac{BTU}{KW\ HR}$

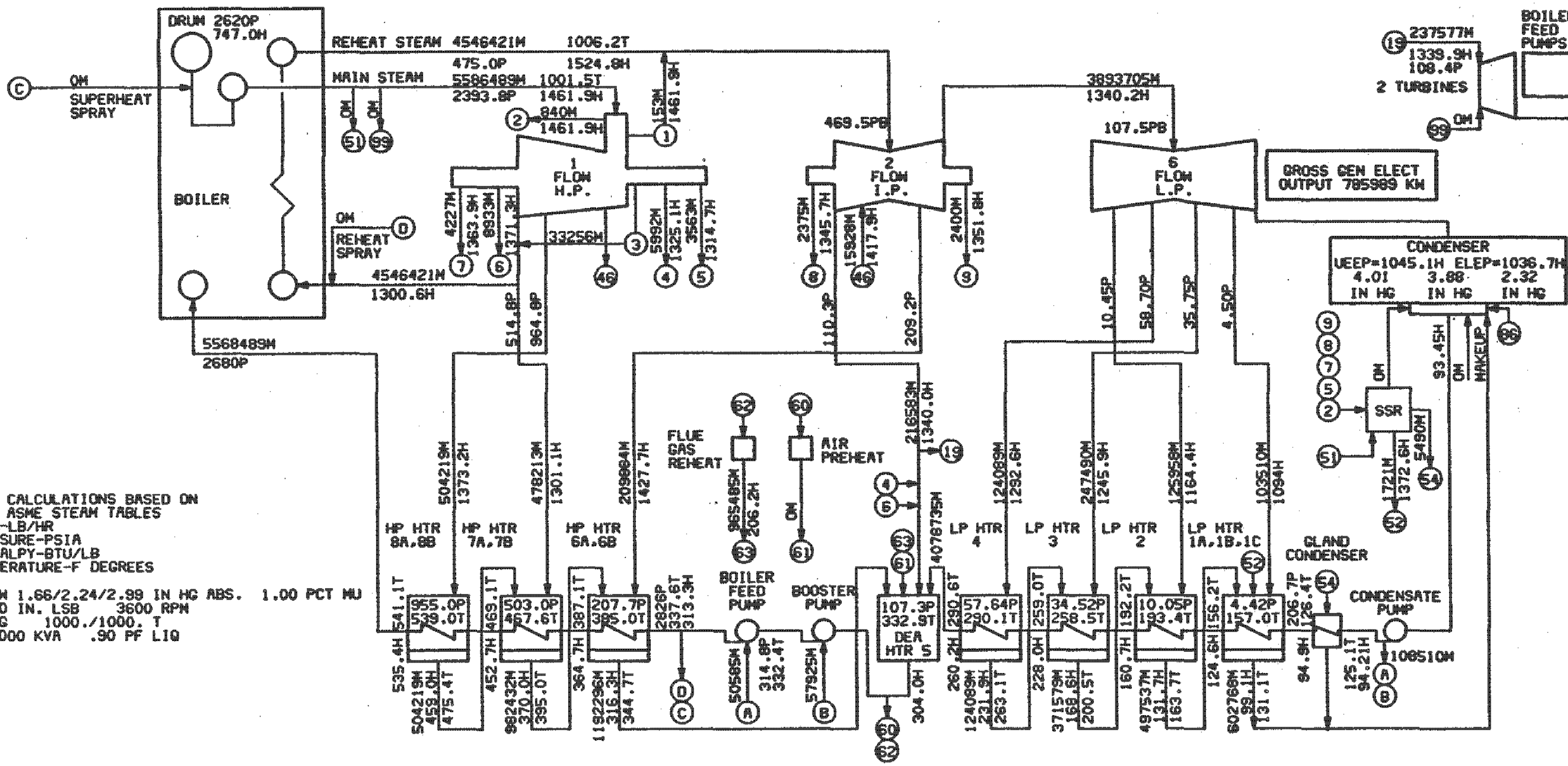
CORRECTED CUSTOMER DEFINED
1% MU HEAT RATE $= 7774 \dfrac{BTU}{KW\ HR}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 2
TEST 6 - VWO HEAT BALANCE

IP14_007362

FIGURE 3-4

ARRANGEMENT IS SCHEMATIC ONLY




LEGEND - CALCULATIONS BASED ON ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

$$\text{TEST HEAT RATE} = \frac{5568489(1461.9-535.4)+5568489(1.50)+4187245(94.2-93.4)+4546421(1524.8-1300.6)+5568(747.0-535.4)}{785989\text{KW}} = 7877 \frac{\text{BTU}}{\text{KW HR}}$$

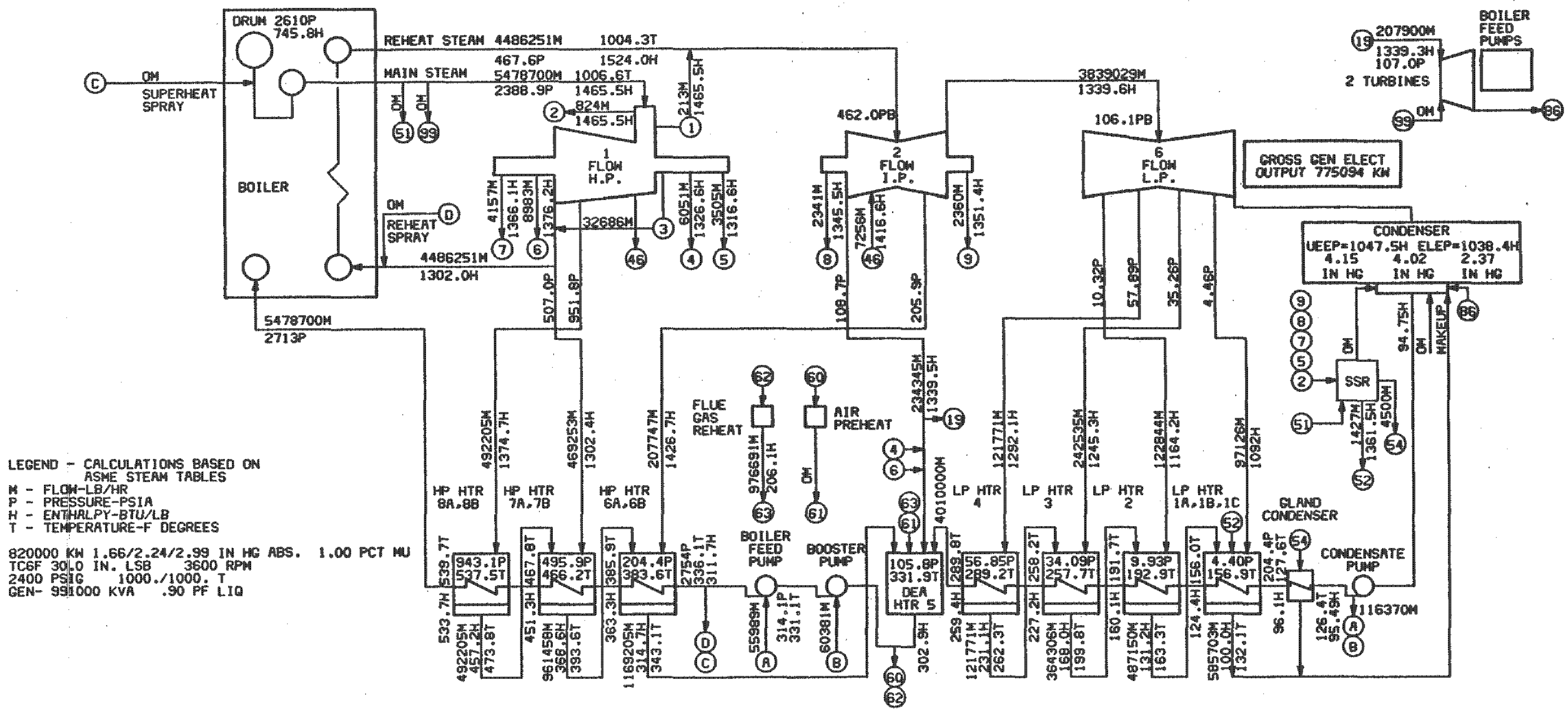
$$\text{CORRECTED CUSTOMER DEFINED 1\% MU HEAT RATE} = 7804 \frac{\text{BTU}}{\text{KW HR}}$$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 2
TEST 5 - THIRD VALVE POINT HEAT BALANCE

IP14_007363

FIGURE 3-5

ARRANGEMENT IS SCHEMATIC ONLY




TEST HEAT RATE = $\frac{5478700(1465.5-533.7)+5478700(1.50)+4126370(95.5-94.8)+4486251(1524.0-1302.0)+5479(745.8-533.7)}{775094KW}$ = 7887 $\frac{BTU}{KW\ HR}$

CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE = 7796 $\frac{BTU}{KW\ HR}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 2
TEST 7 - THIRD VALVE POINT HEAT BALANCE

IP14_007364

ARRANGEMENT IS SCHEMATIC ONLY

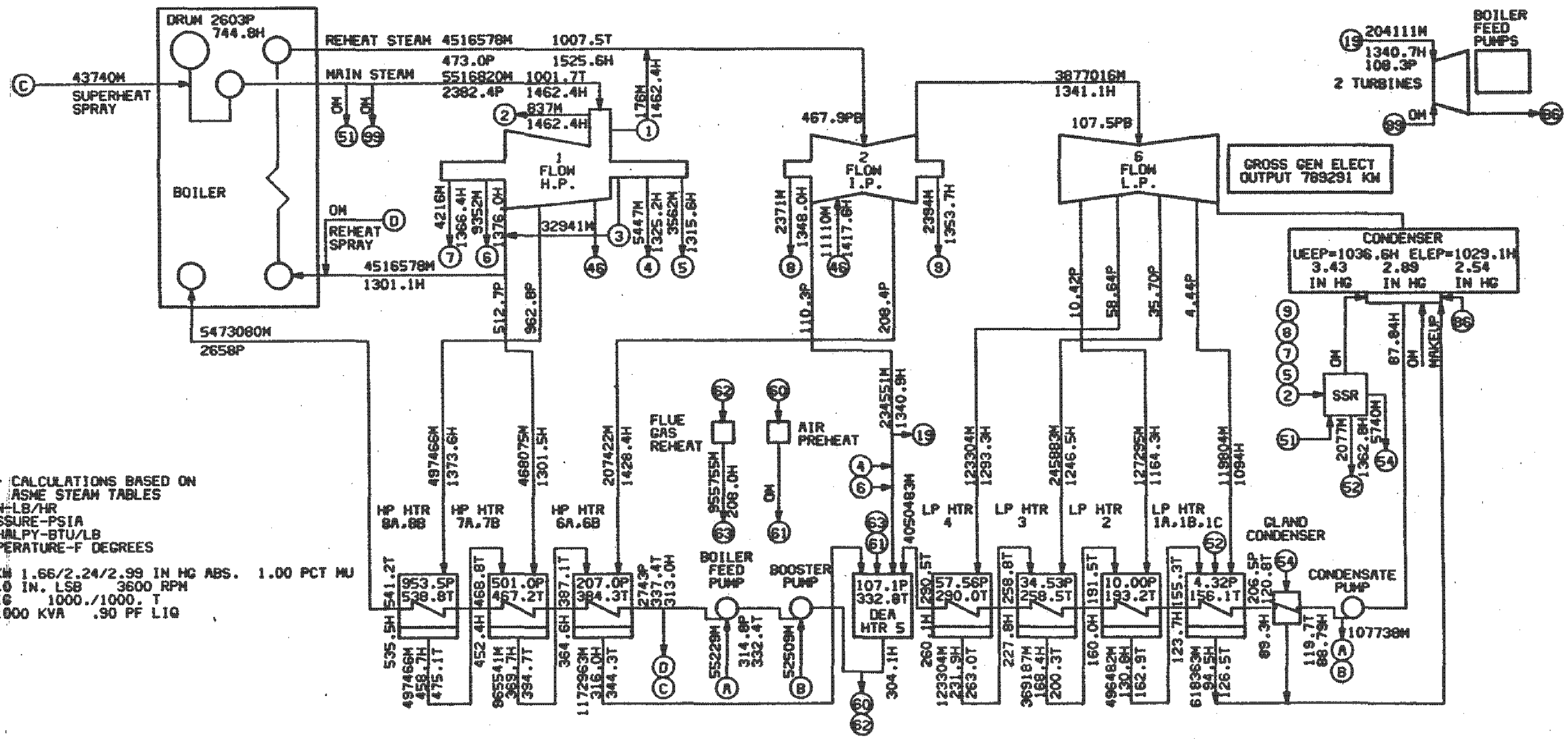



FIGURE 3-6

LEGEND - CALCULATIONS BASED ON ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

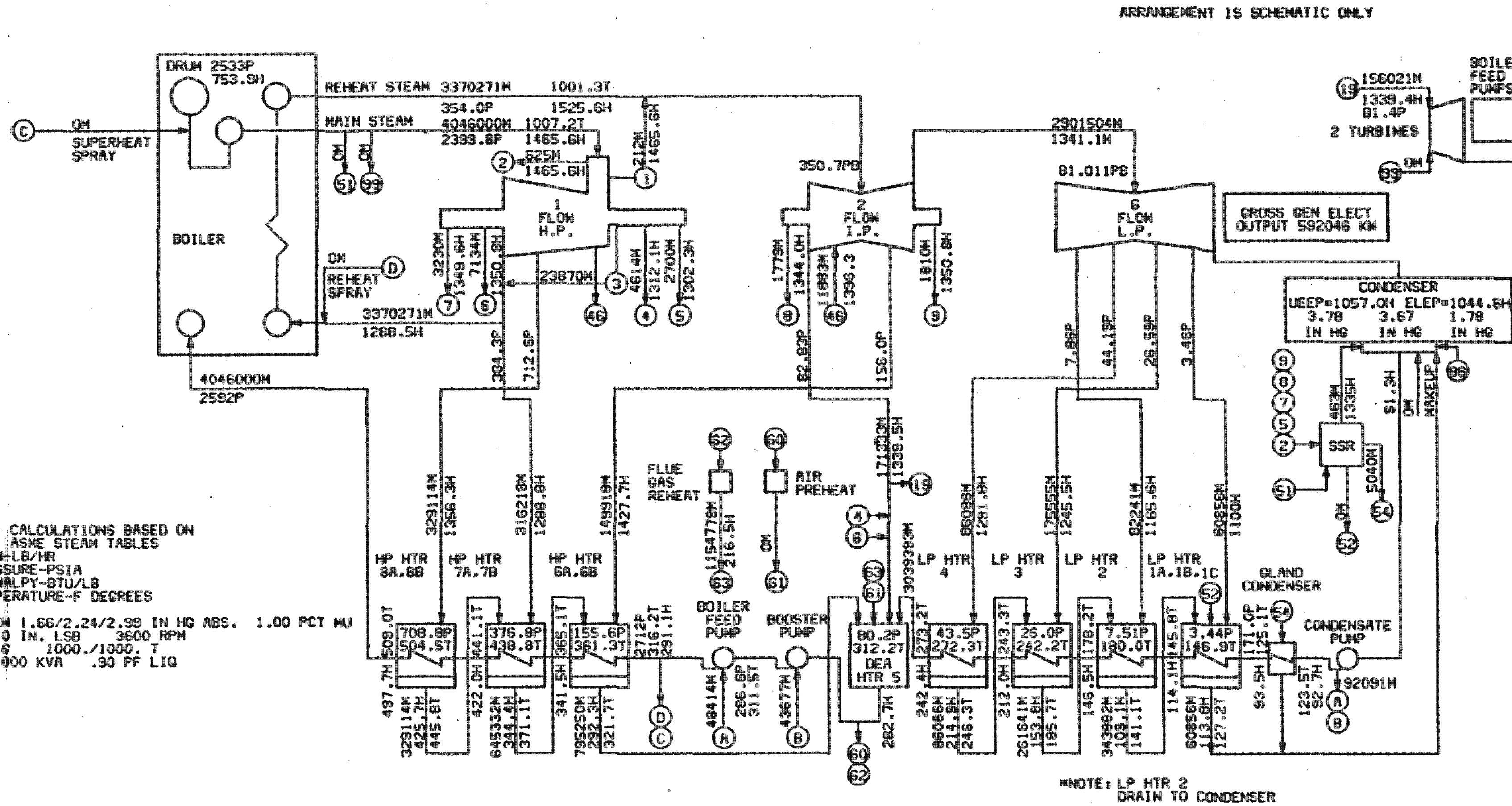
TEST HEAT RATE = $\frac{5473080(1462.4-535.5)+43740(1462.4-313.0)+5516820(1.50)+4158221(88.8-87.8)+4516578(1525.6-1301.1)+5473(744.8-535.5)}{789291\text{KW}} = 7792 \frac{\text{BTU}}{\text{KW HR}}$

CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE = 7788 $\frac{\text{BTU}}{\text{KW HR}}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 2
TEST 10 - THIRD VALVE POINT HEAT BALANCE

IP14_0073365

FIGURE 3-7




LEGEND - CALCULATIONS BASED ON ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

$$\text{TEST HEAT RATE} = \frac{4046000(1465.6-497.7)+4046000(1.77)+3131484(92.7-91.3)+3370271(1525.6-1288.5)+4046(735.9-497.7)}{592046\text{KW}} = 7985 \frac{\text{BTU}}{\text{KW HR}}$$

CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE $= 7920 \frac{\text{BTU}}{\text{KW HR}}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 2
TEST 3 - SECOND VALVE POINT HEAT BALANCE

ARRANGEMENT IS SCHEMATIC ONLY

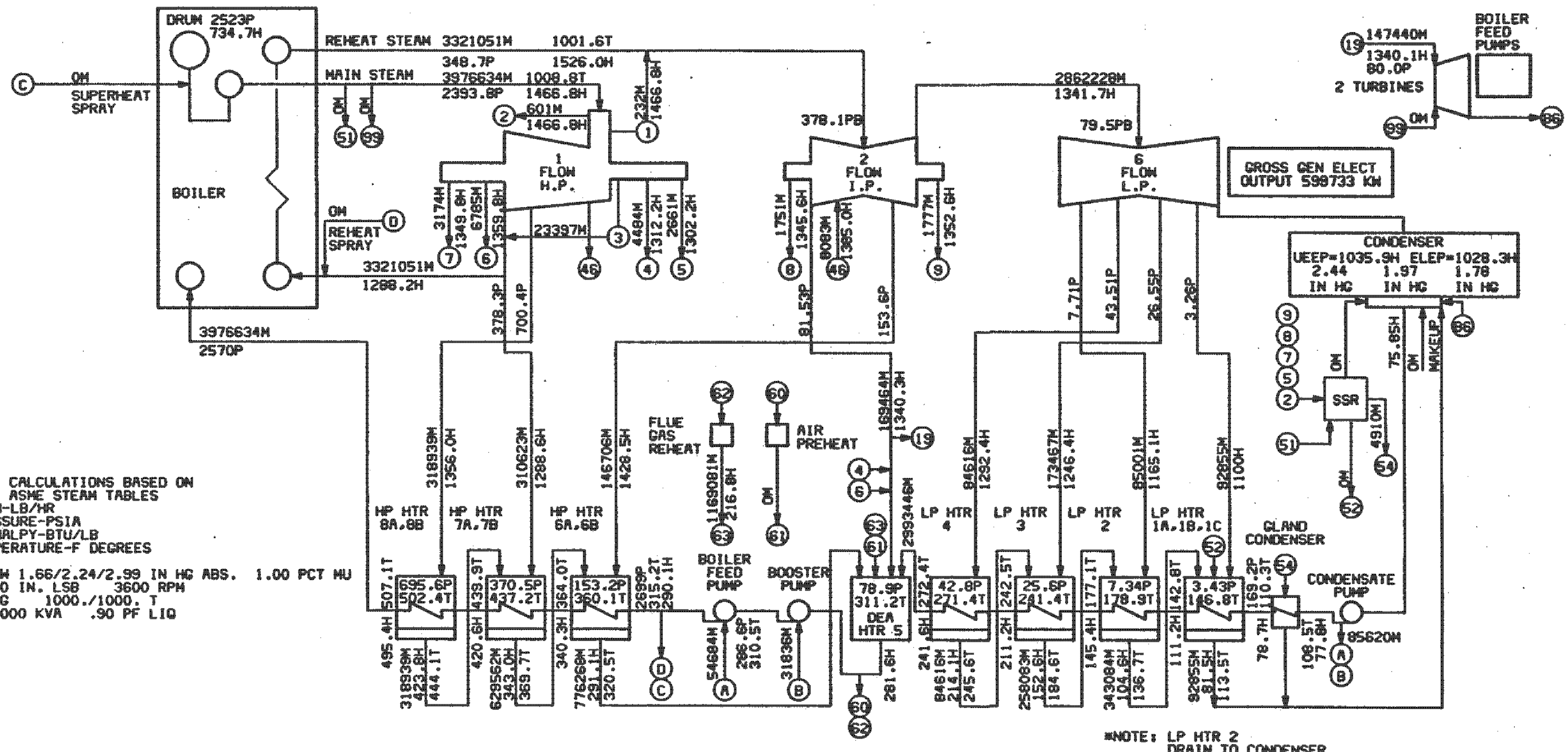



FIGURE 3-8

LEGEND - CALCULATIONS BASED ON ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

$$\text{TEST HEAT RATE} = \frac{3976634(1466.8-495.4)+3976634(1.77)+3079066(77.8-75.9)+3321051(1526.0-1288.2)+3977(734.7-495.4)}{599733\text{KW}} = 7781\ \frac{\text{BTU}}{\text{KW HR}}$$

CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE = 7927 $\frac{\text{BTU}}{\text{KW HR}}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 2
TEST 9 - SECOND VALVE POINT HEAT BALANCE

IP14_0073367

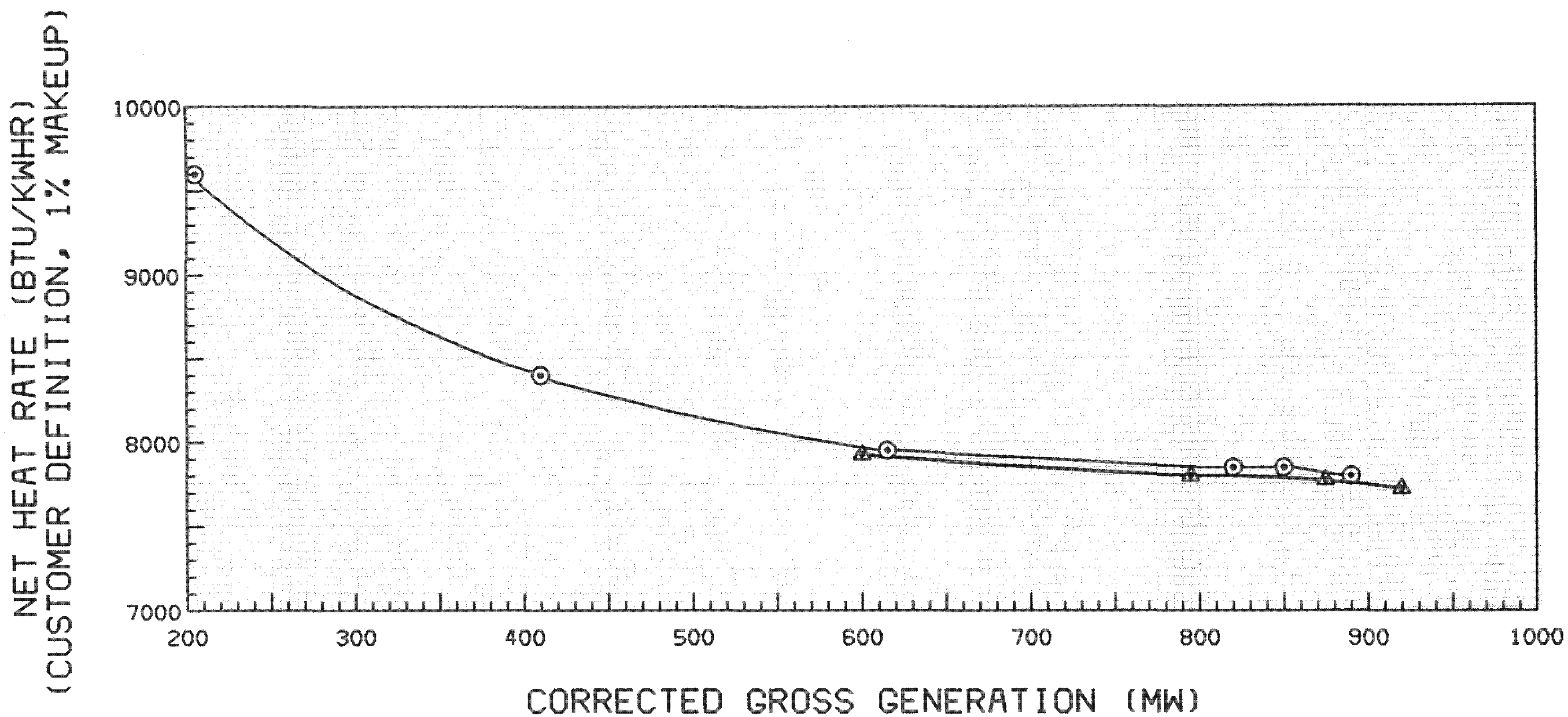



FIGURE 3-9: CORRECTED NET HEAT RATE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

KEY:
⊙ 1% MU HEAT BALANCE
▲ B&V CALCULATED HEAT RATE, 1% MU

IP14_007368

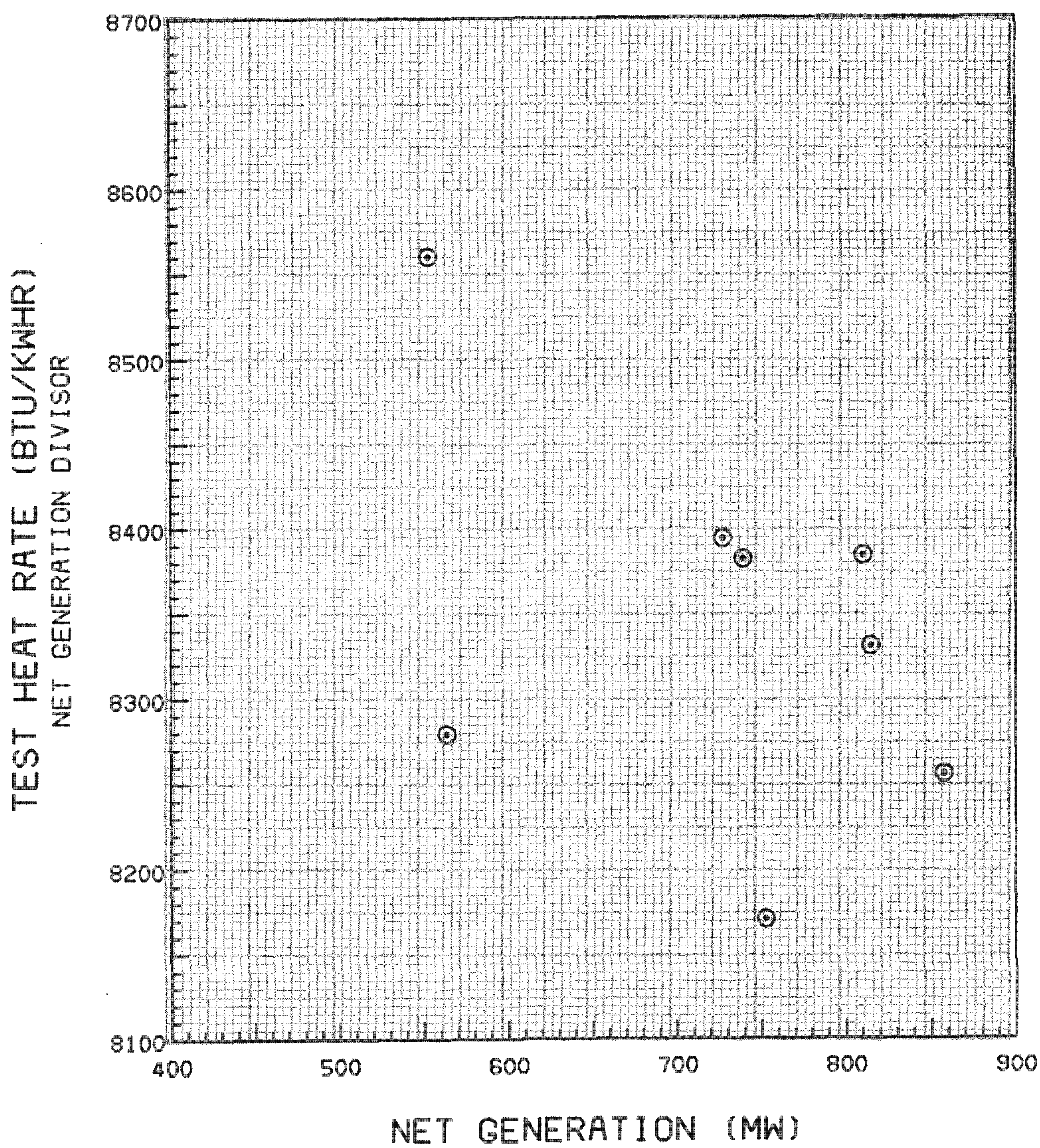



FIGURE 3-10: TEST HEAT RATE VS NET GENERATION
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

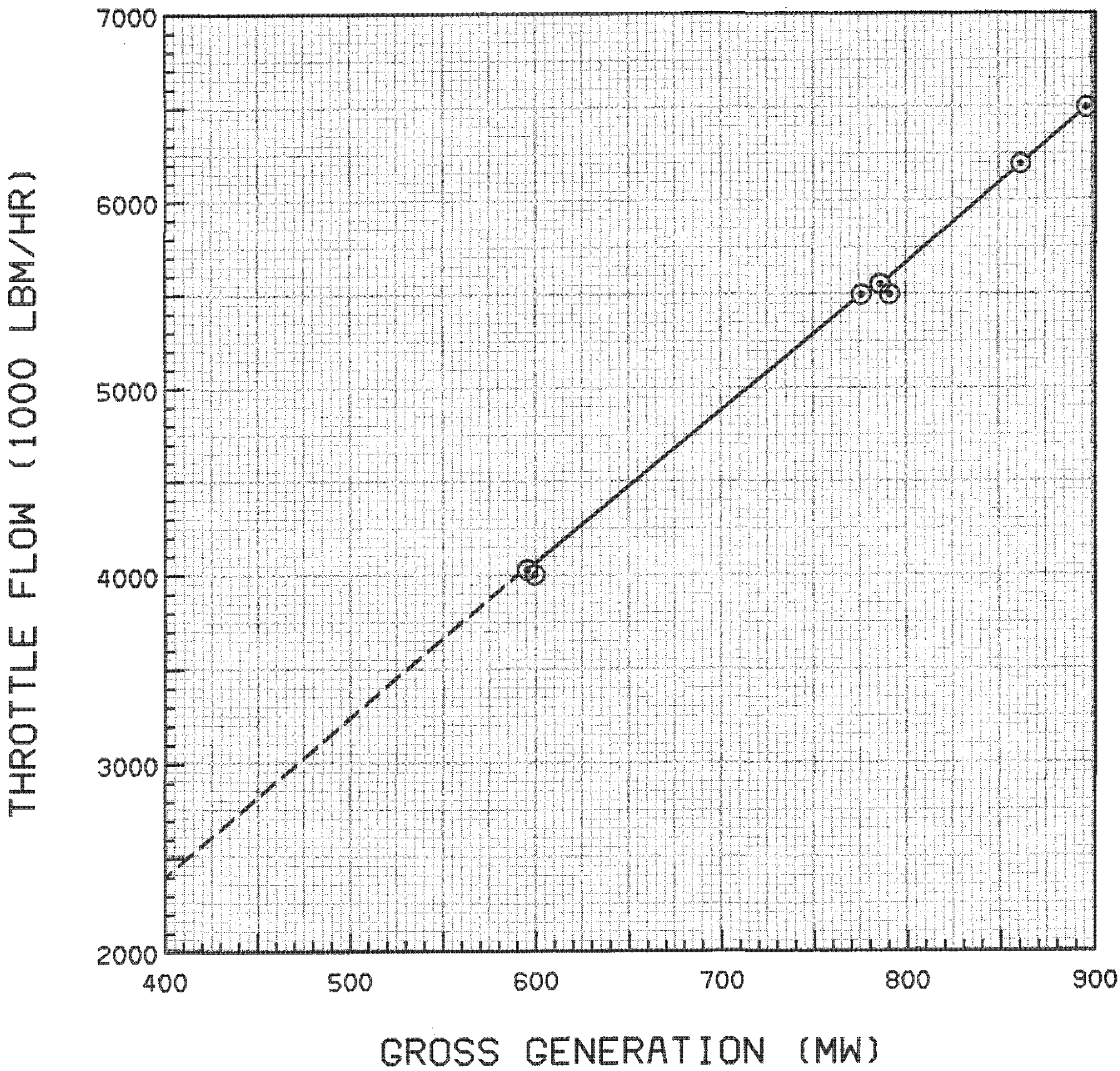



FIGURE 3-11: THROTTLE FLOW VS GROSS GENERATION
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

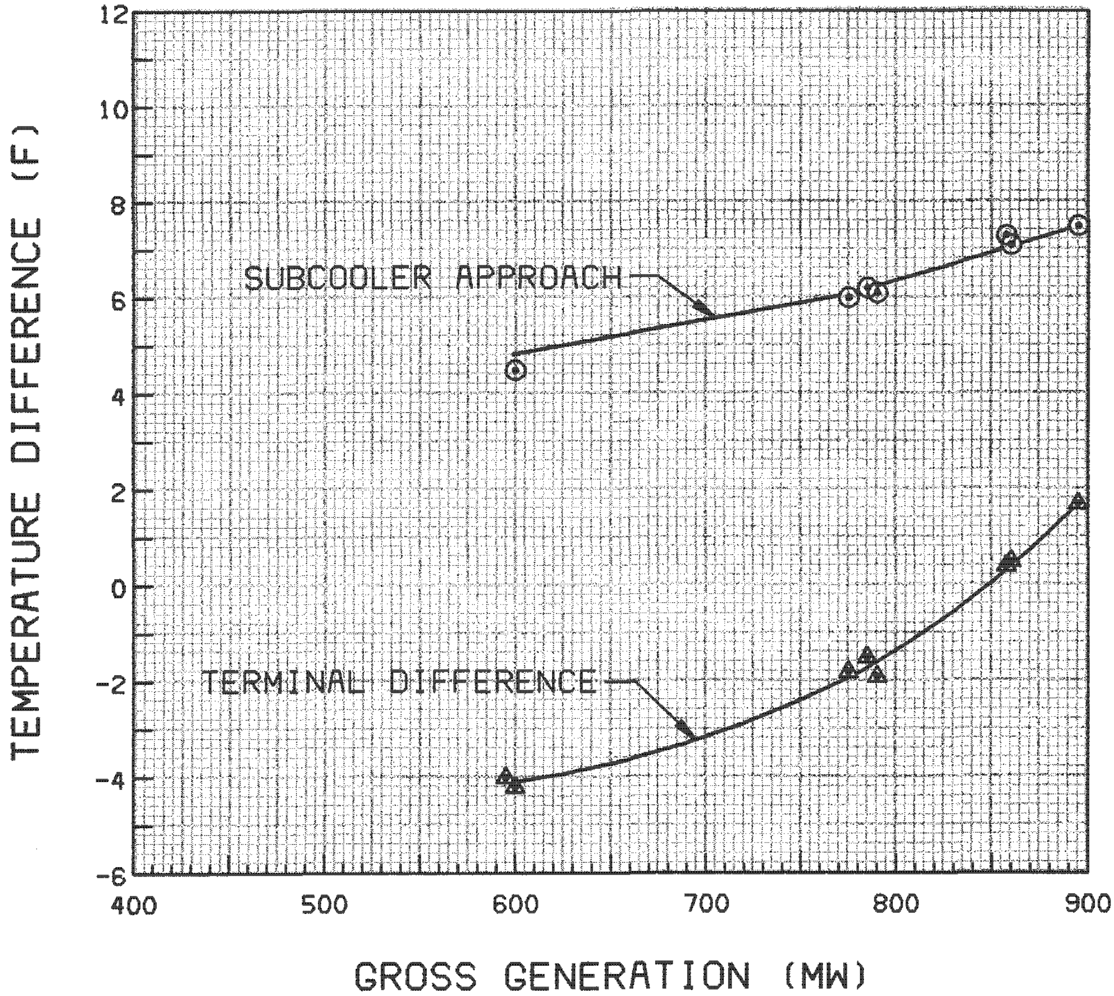



FIGURE 3-12: HEATER 8A PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

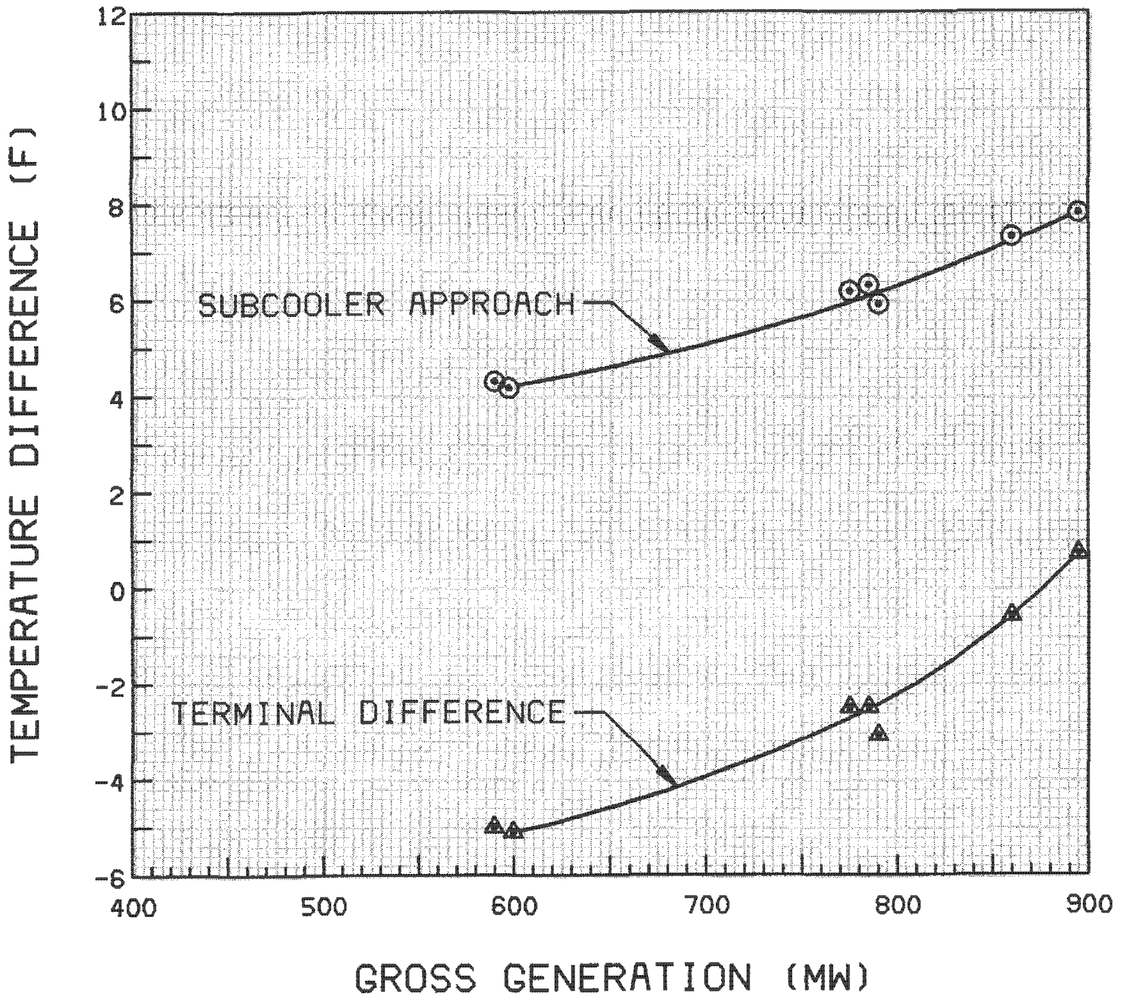



FIGURE 3-13: HEATER 8B PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

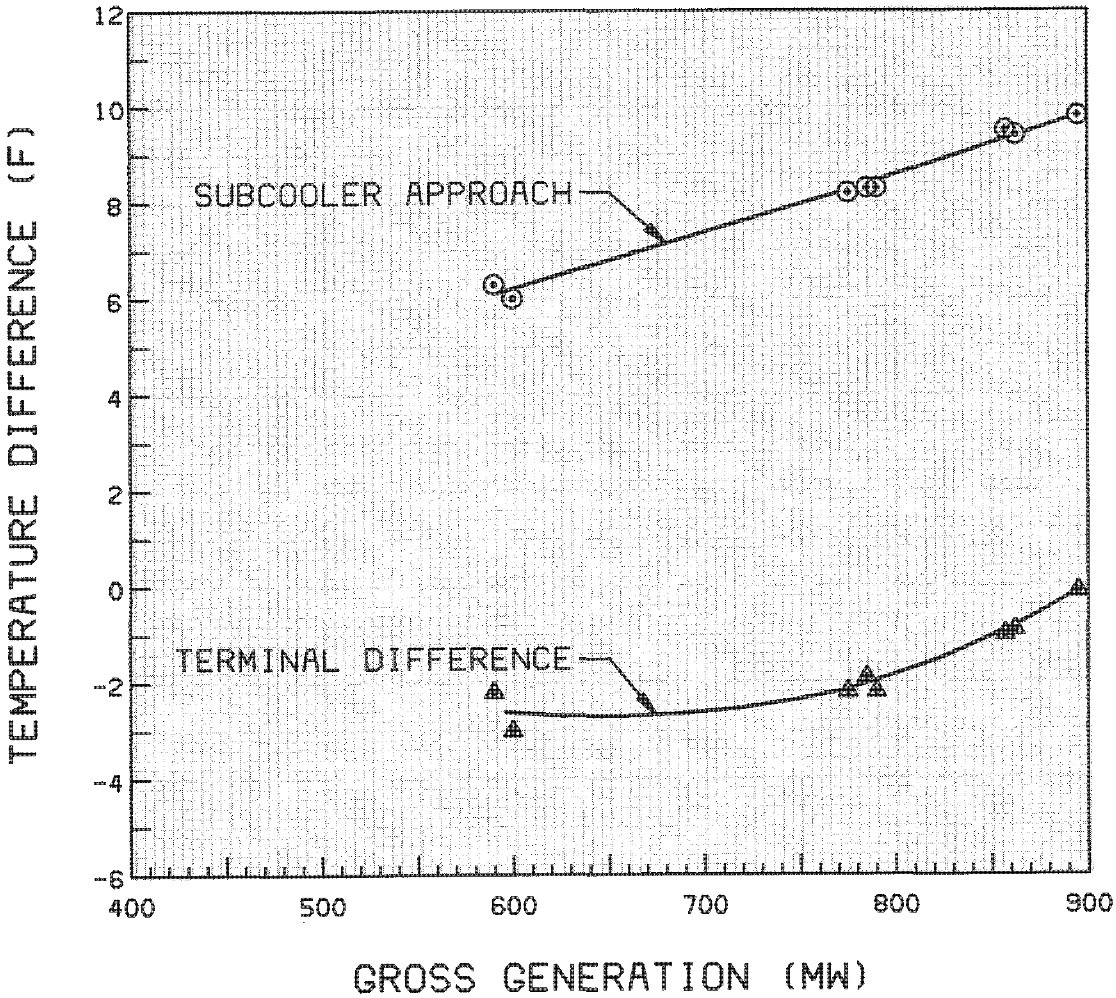



FIGURE 3-14: HEATER 7A PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

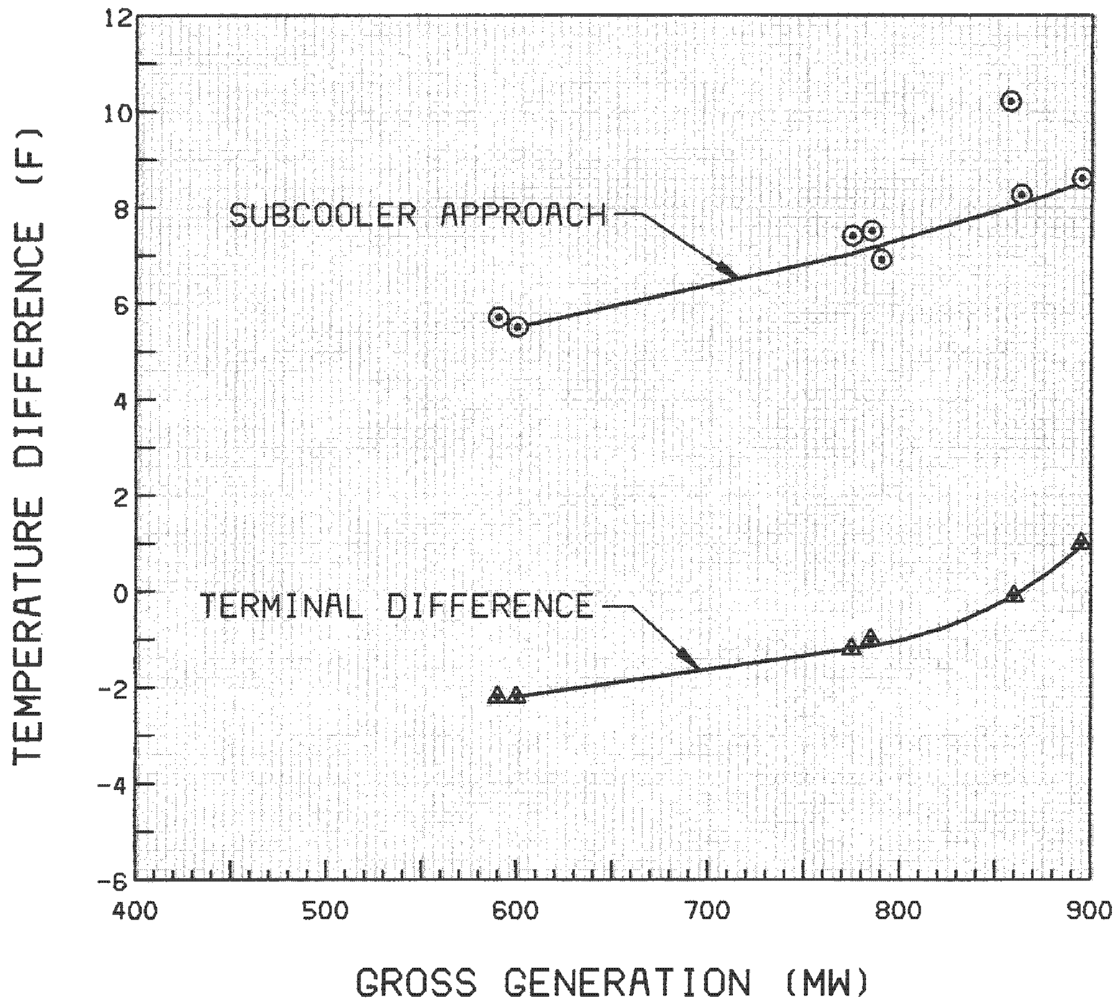



FIGURE 3-15: HEATER 7B PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

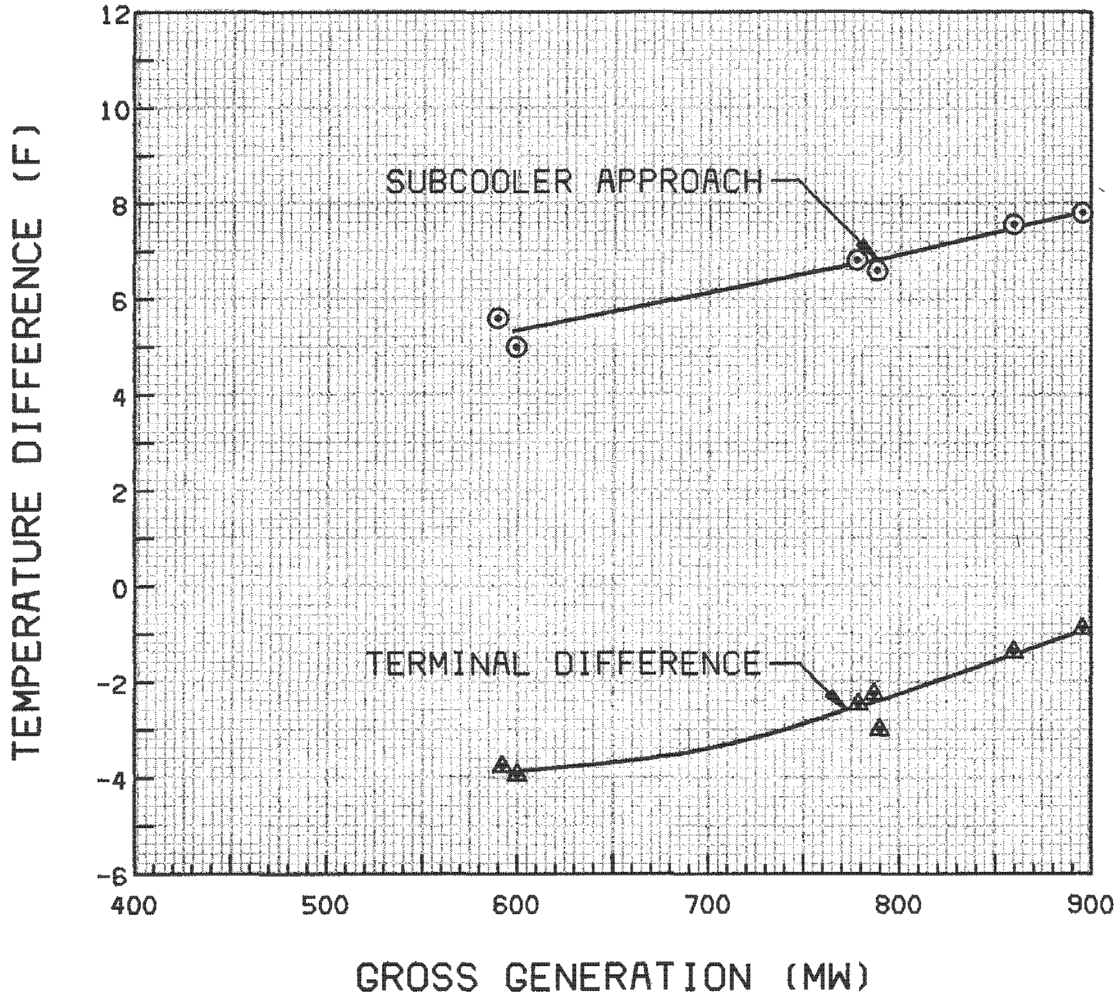



FIGURE 3-16: HEATER 6A PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

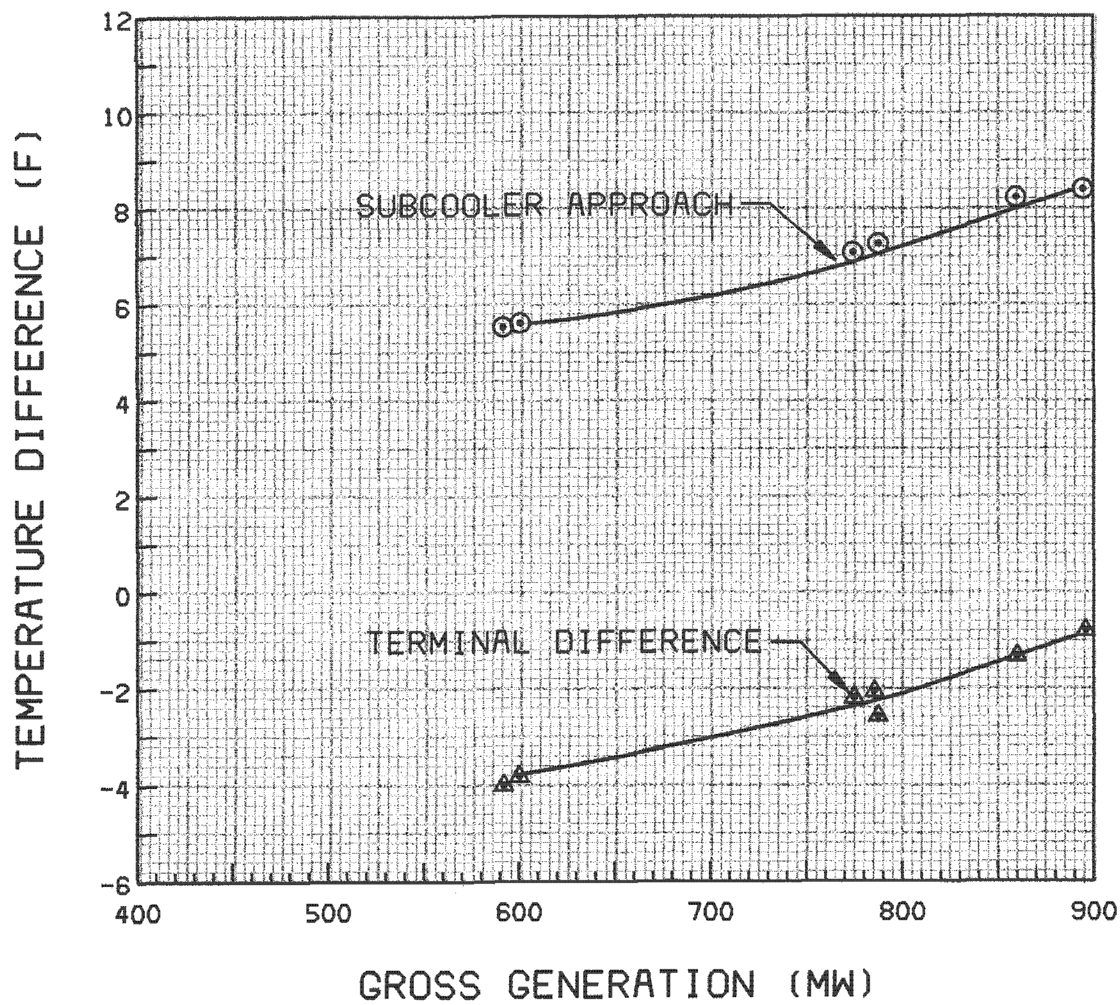



FIGURE 3-17: HEATER 6B PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

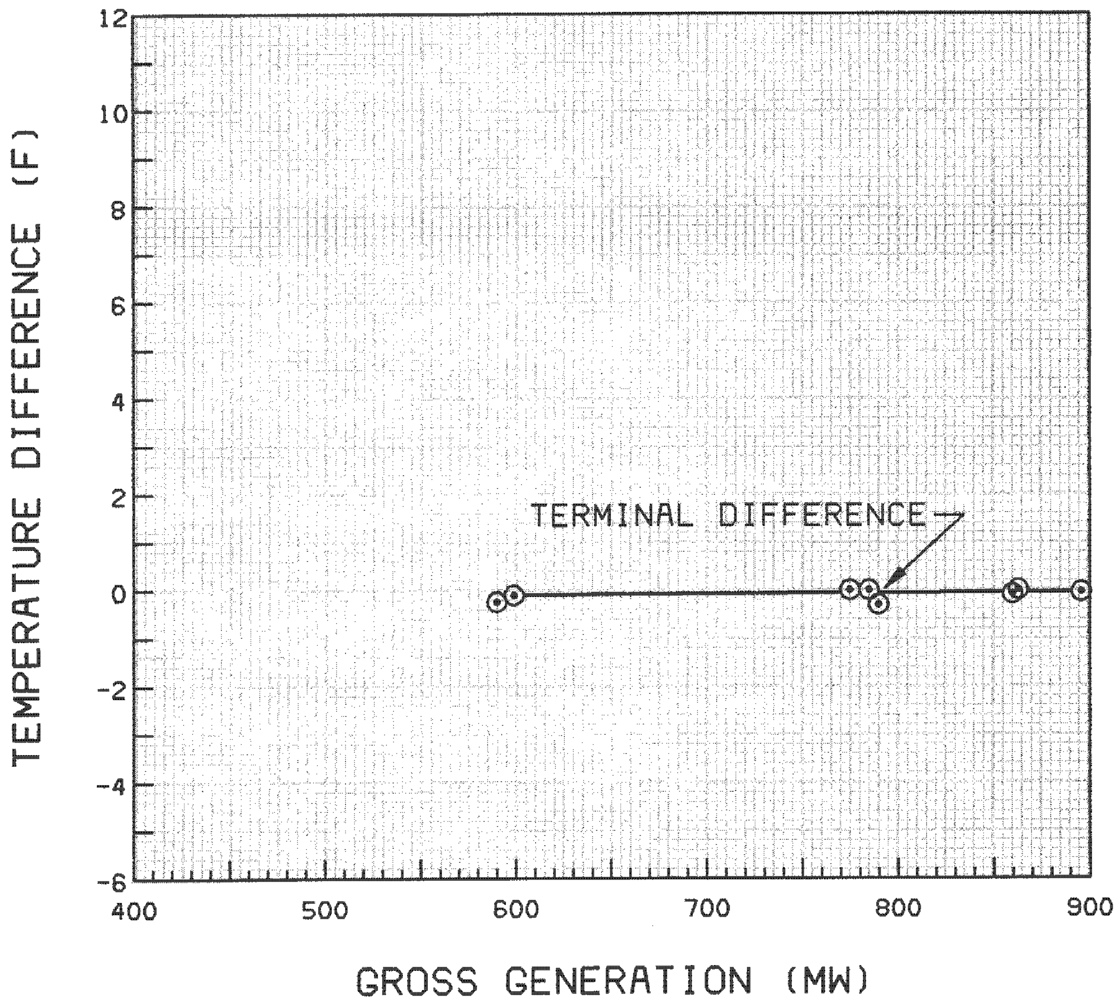



FIGURE 3-18: HEATER 5 PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

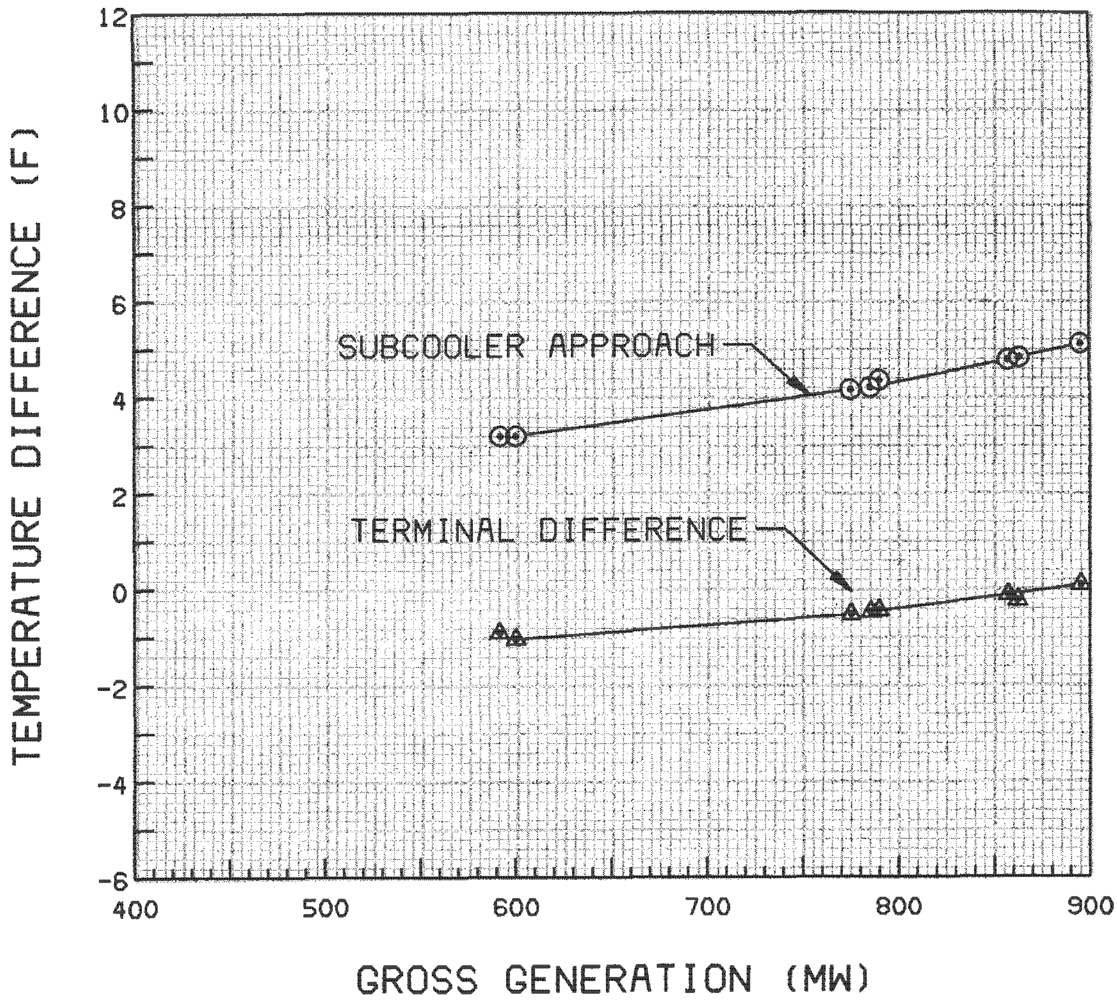



FIGURE 3-19: HEATER 4 PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

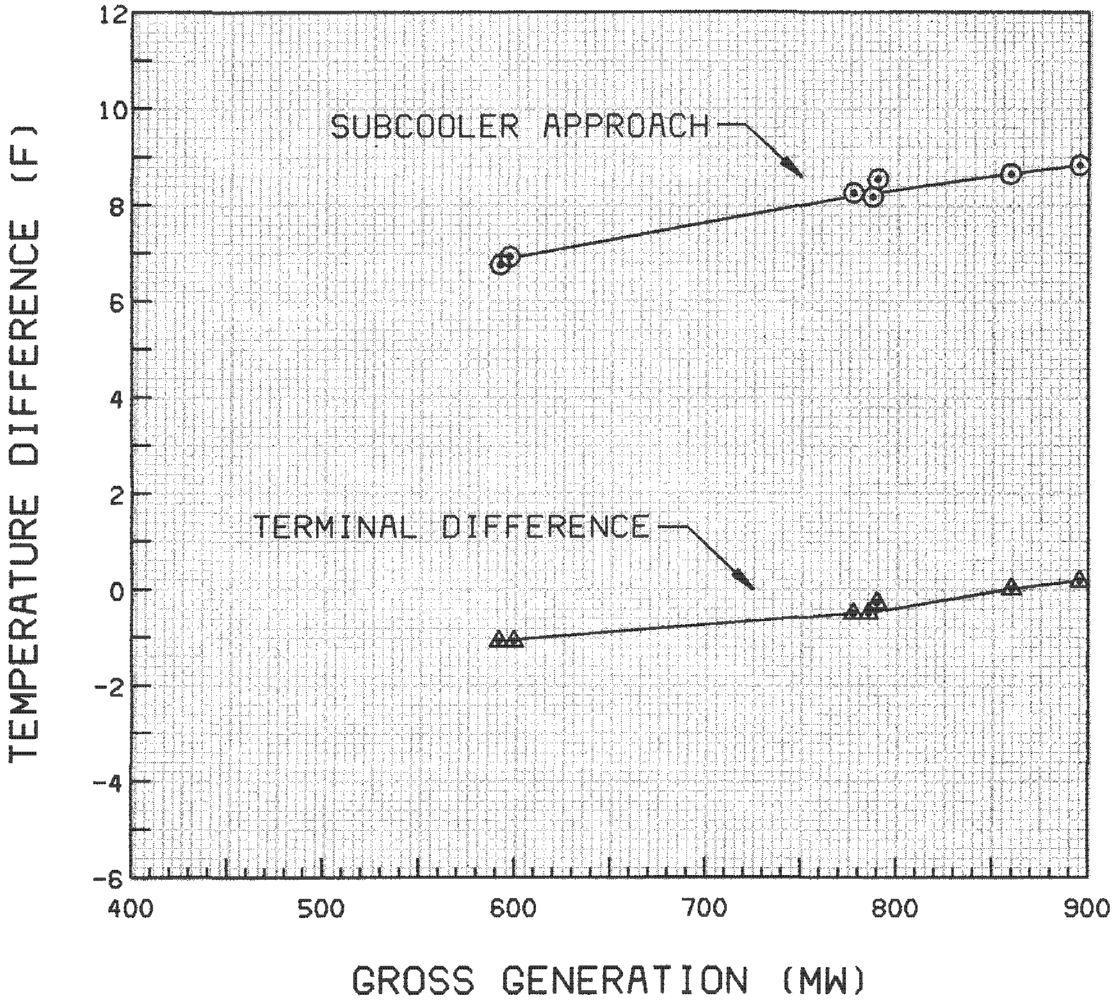



FIGURE 3-20: HEATER 3 PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

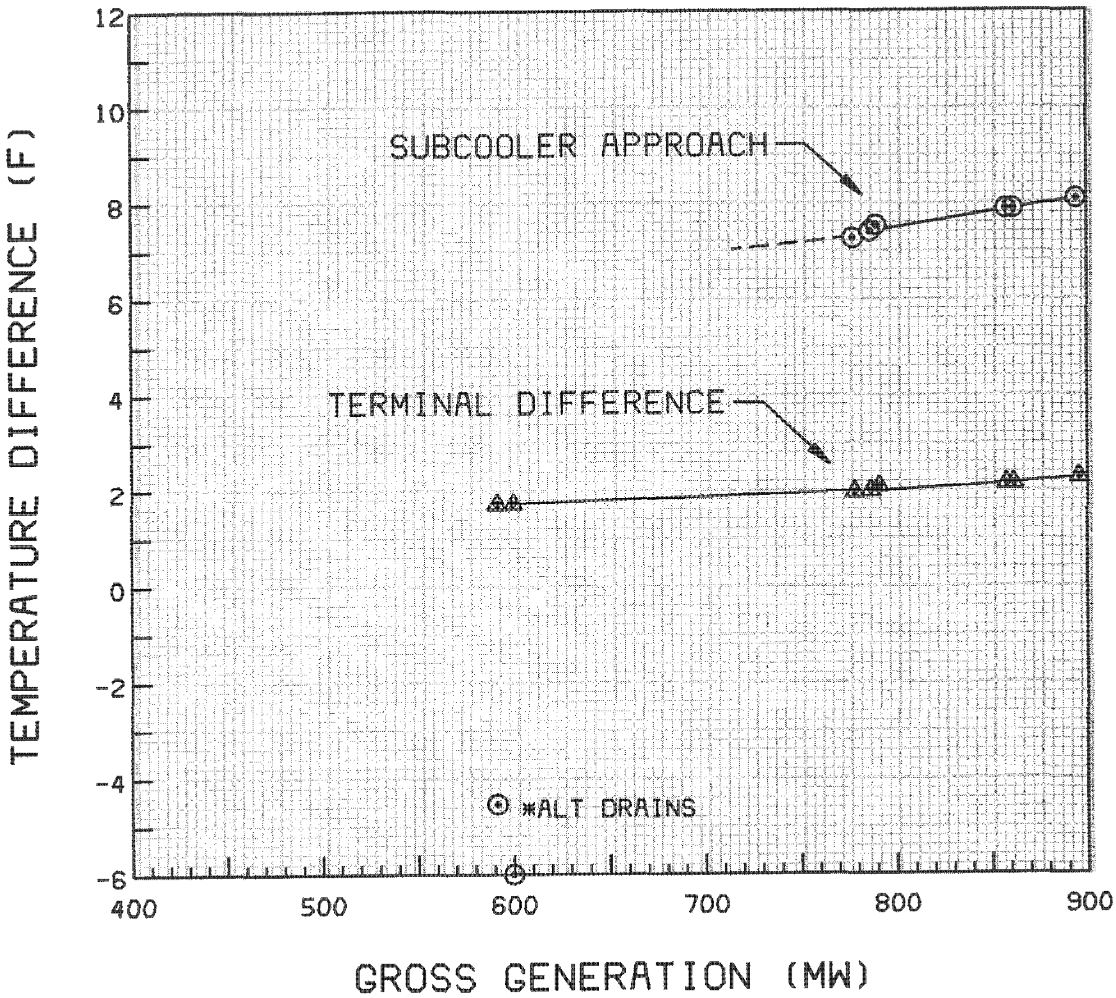
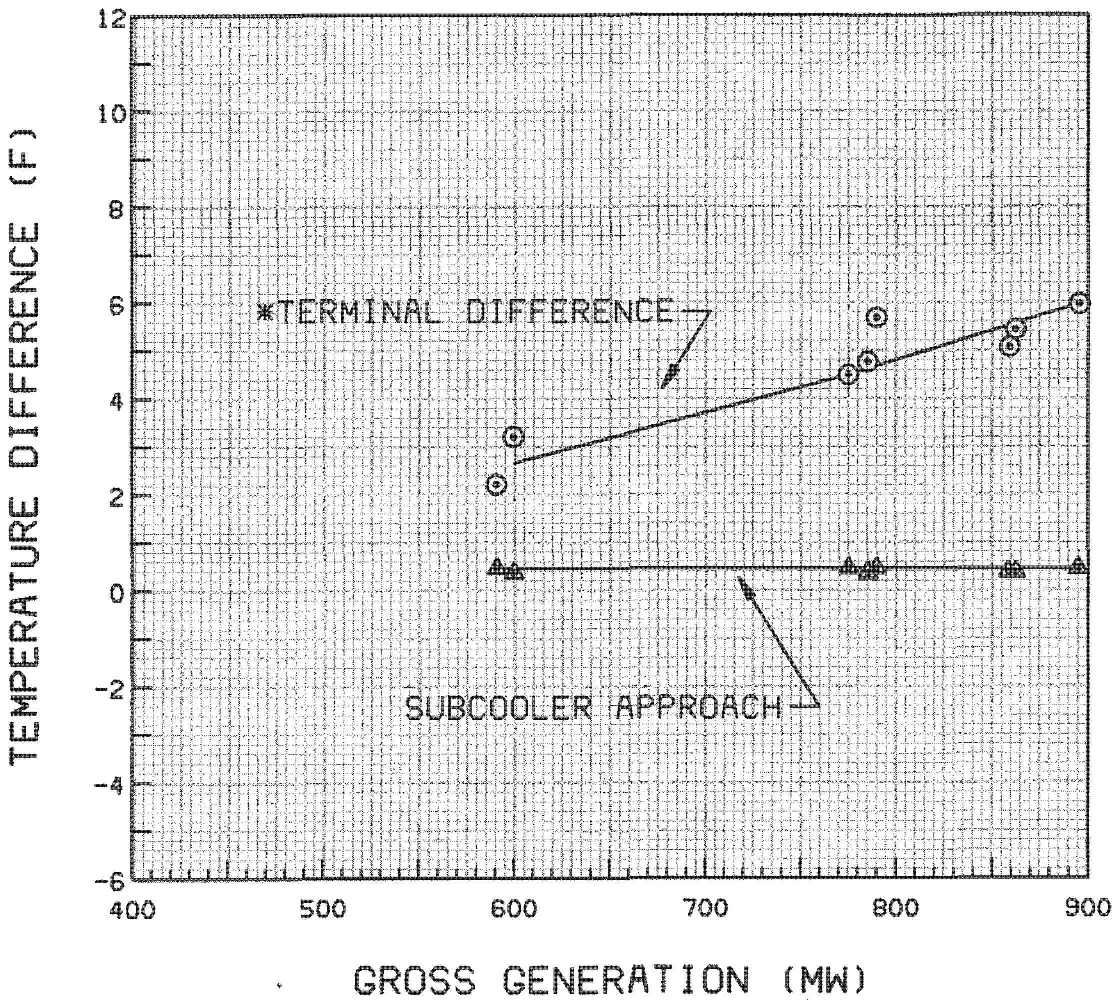



FIGURE 3-21: HEATER 2 PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2



* DOES NOT INCLUDE HEATER 1C TERMINAL DIFFERENCE

FIGURE 3-22: HEATER 1 PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 2

# 4.0 PROCEDURE

The performance test was conducted to determine net plant heat rate, and the performance and efficiencies of the major equipment in the cycle. Data collected also establishes bench mark data for the unit.

Preliminary tests were conducted to check operation and readings of all instruments directly related to the test. This also allowed determination of cycle leakages for isolation purposes.

Eight tests were conducted: two each at valves wide open and at second valve point, three at third valve point, and one at valves wide open 5 percent overpressure. Data was collected by General Electric test computer, the plant computer, and manually. Pressures, temperatures, important flow measurements, and generator output were carefully measured with highly accurate measuring instruments. Balance-of-plant measurements were taken by plant instruments or by hand. All instruments were to be calibrated before testing commenced.

Generally, the tests began one hour after the unit had stabilized and were two hours in duration. Blowdown and makeup were isolated for the tests. Combustion conditions, rate of fuel flow, rate of feedwater flow, drum level, excess air, and all controllable temperatures and pressures were maintained as constant as possible for the duration of each test.

Data for each test were analyzed as soon as practicable after each test for acceptance.

The steam feedwater cycle was isolated as much as practicable to prevent large leakages. The condenser level was monitored to determine losses. Valves closed in the cycle for isolation are listed on the following pages.

VALVE ISOLATION LIST

AUXILIARY STEAM SYSTEM
P&I DIAGRAM 9PSA-M2008

| Class | Description | Valve Number |
|---|---|---|
| N | Makeup from Unit 1 Deaerator | 9PSA-BV-16 |
| N | Makeup from Unit 1 Deaerator | 9PSA-BV-18 |
| N | Makeup from Unit 1 Deaerator | 9PSA-BV-20 |
| N | Makeup from Unit 1 Deaerator | 9PSA-BV-22 |

N - Non-critical

C - Critical

AUXILIARY STEAM SYSTEM
P&I DIAGRAM 2PSA-M2008

| Class | Description | Valve Number |
|---|---|---|
| N | Cold Reheat to Aux Steam | 2PSA-MBV-17 |
| | Use Telltale Valves 36 and 37 to verify isolation. | |
| N | Cold Reheat to Aux Steam | 2PSA-BV-15 |
| N | Cold Reheat to Aux Steam | 2PSA-BV-11 |
| N | Cold Reheat to Aux Steam | 2PSA-BV-12 |
| | Use Telltale Valves 123 and 127 to verify isolation. | |
| N | Cold Reheat to Aux Steam | 2PSA-BV-13 |
| N | Cold Reheat to Aux Steam | 2PSA-BV-14 |
| | Use Telltale Valves 123 and 127 to verify isolation. | |
| N | Aux Steam to Deaerator | 2PSA-BV-22 |
| N | Aux Steam to Deaerator | 2PSA-BV-21 |
| | Use Vent Valve 118 to verify isolation. | |
| N | Aux Steam to Deaerator Storage Tank | 2PSA-BV-133 |
| | Use Telltale Valve 134 to verify isolation. | |
| N | Aux Steam to Deaerator Storage Tank | 2PSA-BV-6 |
| N | Aux Steam to BFPT | 2PSA-BV-19 |
| N | Aux Steam to BFPT | 2PSA-BV-18 |
| | Use Telltale Valves 39 and 40 to verify isolation. | |
| N | Aux Steam to Turbine Seals | 2PSA-BV-26 |
| N | CNDS to Aux Steam Desuperheater | 2PSA-BV-7 |
| N | CNDS to Aux Steam Desuperheater | 2PSA-BV-8 |
| N | CNDS to Aux Steam Desuperheater | 2PSA-BV-9 |
| N | Cold Reheat to Aux Steam Telltale | 2PSA-BV-37 |
| N | Main Deaerator Preheating Steam Vent | 2PSA-BV-118 |

AUXILIARY STEAM SYSTEM (Continued)
P&I DIAGRAM 2PSA-M2008

| Class | Description | Valve Number |
|---|---|---|
| N | Deaerator Storage Tank Condensate Deaeration Steam Telltale | 2PSA-BV-134 |
| N | BFPT Startup Steam Telltale | 2PSA-BV-40 |
| N | Cold Reheat to Aux Steam Telltale | 2PSA-BV-36 |
| N | Steam From Secondary Superheater | 2PSA-BV-58 |
| N | Steam Trap No. 5 | 2PSA-BV-82 |
| N | Steam Trap No. 5 | 2PSA-BV-83 |

N - Non-critical

C - Critical

## COMBUSTION GAS REHEAT SYSTEM
## P&I DIAGRAM 2CCD-M2013A

| Class | Description | Valve Number |
|---|---|---|
| N | Deaerator to Combustion Gas Reheat | 2CCD-BV-150 |
| | Use telltale valve to verify isolation. | |
| N | Deaerator to Combustion Gas Reheat | 2CCD-BV-435 |
| N | Steam From Secondary Superheater Platen Outlet Header | 2CCD-BV-44 |
| N | Steam From Secondary Superheater Platen Outlet Header | 2CCD-BV-47 |
| N | Normal Return to Condensate Header Downstream of Heater 2 Telltale | 2CCD-BV-436 |
| N | Combustion Gas Reheat Pumps Recirculation | 2CCD-BV-110 |
| N | Combustion Gas Reheat Pumps Recirculation | 2CCD-BV-113 |
| N | Combustion Gas Reheat Pumps Recirculation | 2CCD-BV-114 |
| N | Combustion Gas Reheat Pumps Recirculation | 2CCD-BV-117 |
| N | AQCS RH Soot Blower Condensate Return | 2CCD-BV-125 |
| N | AQCS RH Soot Blower Condensate Return | 2CCD-BV-127 |
| N | Attemperator Spray From BFP Discharge | 2CCD-BV-137 |
| N | Attemperator Spray From BFP Discharge | 2CCD-BV-139 |
| N | Attemperator Spray From BFP Discharge | 2CCD-BV-142 |

NOTE: Use Temperature Elements 903, 904, and 905 to verify system isolation.

N - Non-critical

C - Critical

CONDENSING SYSTEM
P&I DIAGRAM 2HRA-M2020

| Class | Description | Valve Number |
|---|---|---|
| C | Condensate Makeup | 2HRA-BV-30 |
| C | Condensate Makeup | 2HRA-BV-31 |
| C | Condensate Makeup | 2HRA-ACV-32 |
| N | Condensate Makeup | 2HRA-BV-33 |
| N | Condensate Makeup | 2HRA-BV-34 |
| C | Condensate Drawoff | 2HRA-BV-19 |
| C | Condensate Drawoff | 2HRA-BV-20 |
| N | Condensate Drawoff | 2HRA-BV-23 |
| N | Condensate Drawoff | 2HRA-BV-24 |
| N | Condensate Pump Seals | 2HRA-BV-71 |
| | Use Telltale Valve 178 to verify isolation. | |
| N | Condensate Pump Seals | 2HRA-BV-179 |
| N | Condensate Pump Recirc | 2HRA-ACV-25 |
| N | Condensate Pump Recirc | 2HRA-BV-29 |
| N | Condensate Normal Makeup Drain | 2HRA-BV-148 |
| N | Condensate Emergency Makeup Telltale | 2HRA-BV-175 |
| N | Condensate Normal Drawoff Telltale | 2HRA-BV-176 |
| N | Condensate Emergency Drawoff Telltale | 2HRA-BV-177 |
| N | Condensate Misc Service Pumps Telltale | 2HRA-BV-178 |
| N | Hot Well Drain | 2HRA-BV-89 |
| N | Hot Well Drain | 2HRA-BV-90 |
| N | Hot Well Drain | 2HRA-BV-91 |
| N | Hydrazine Feed | 2HRA-BV-92 |
| N | Condenser Leak Detection Sample | 2HRA-BV-112 |
| N | Condenser Leak Detection Sample | 2HRA-BV-113 |
| N | Condenser Leak Detection Sample | 2HRA-BV-114 |
| N | Condenser Leak Detection Sample | 2HRA-BV-115 |
| N | Condenser Leak Detection Sample | 2HRA-BV-116 |
| N | Condenser Leak Detection Sample | 2HRA-BV-117 |

CONDENSING SYSTEM (Continued)
P&I DIAGRAM 2HRA-M2020

| Class | Description | Valve Number |
|---|---|---|
| N | Condenser Leak Detection Sample | 2HRA-BV-118 |
| N | Condenser Leak Detection Sample | 2HRA-BV-119 |

N - Non-critical

C - Critical

CONDENSER AIR EXTRACTION
P&I DIAGRAM 2HRB-M2021

| Class | Description | Valve Number |
|---|---|---|
| C | Separator Makeup | 2HRB-BV-109 |
| C | Separator Makeup | 2HRB-BV-110 |
| C | Separator Makeup | 2HRB-BV-111 |
| C | Separator Makeup | 2HRB-BV-112 |

N - Non-critical

C - Critical

BOILER FEED SYSTEM
P&I DIAGRAM 2FWA-M2035A

| Class | Description | Valve Number |
|---|---|---|
| C | BFP Recirculation | 2FWA-ACV-14 |
| C | BFP Recirculation | 2FWA-ACV-15 |
| C | BFP Recirculation | 2FWA-ACV-16 |
| C | BFP Recirculation | 2FWA-ACV-17 |
| C | BFP Recirculation | 2FWA-ACV-18 |
| C | BFP Recirculation | 2FWA-ACV-19 |
| C | BFP Recirculation | 2FWA-BV-37 |
| N | Boot Strap Startup | 2FWA-BV-298 |
| | Use Telltale Valve 108 to verify isolation. | |
| N | Boot Strap Startup | 2FWA-BV-299 |
| N | Warmup Drain to Condenser | 2FWA-BV-188 |
| | Use Telltale Valve 365 to verify isolation. | |
| N | Warmup Drain to Condenser | 2FWA-MBV-189 |
| N | Boot Strap Startup Line Telltale | 2FWA-BV-108 |
| N | Warmup Drain to Condenser Telltale | 2FWA-BV-365 |
| N | Warmup Drain to Condenser Telltale | 2FWA-BV-107 |

NOTE: All drains and vents to floor drains or atmosphere should be checked for leakage.

N - Non-critical

C - Critical

BOILER FEED SYSTEM
P&I DIAGRAM 2FWA-M2035B

| Class | Description | Valve Number |
|---|---|---|
| C | Feedwater Heater Bypass | 2FWA-MBV-44 |
| N | Economizer Inlet Header Drain | 2SGA-BV-131 |
| N | Economizer Inlet Header Drain | 2SGA-BV-132 |
| C | Sample No. 11 | 2FWA-BV-202 |
| C | Sample No. 11 | 2FWA-BV-203 |

N - Non-critical

C - Critical

DRAINS AND VENTS
P&I DIAGRAM 2FWA-M2035C

| Class | Description | Valve Number |
|---|---|---|
| N | BFPT Drains | 2FWA-ABV-303 |
| N | BFPT Drains | 2FWA-ABV-304 |
| N | BFPT Drains | 2FWA-ABV-305 |
| N | BFPT Drains | 2FWA-ABV-306 |
| N | BFPT Drains | 2FWA-ABV-307 |
| N | BFPT Drains | 2FWA-ABV-308 |
| N | BFPT Drains | 2FWA-ABV-309 |
| N | BFPT Drains | 2FWA-ABV-310 |
| N | BFPT Drains | 2FWA-ABV-311 |
| N | BFPT Drains | 2FWA-ABV-312 |
| C | BFPT Drains | 2FWA-BV-388 |
| C | BFPT Drains | 2FWA-BV-389 |
| C | BFPT Drains | 2FWA-BV-390 |
| C | BFPT Drains | 2FWA-BV-391 |
| C | BFPT Drains | 2FWA-BV-393 |

N - Non-critical

C - Critical

CONDENSATE SYSTEM
P&I DIAGRAM 2FWC-M2037

| Class | Description | Valve Number |
|---|---|---|
| N | Feedwater Heater Bypasses | 2FWC-MBV-9 |
| N | Feedwater Heater Bypasses | 2FWC-MBV-16 |
| N | Feedwater Heater Bypasses | 2FWC-MBV-17 |
| N | Feedwater Heater Bypasses | 2FWC-MBV-18 |
| N | Deaerator Drain to Condenser | 2FWC-BV-85 |
| | Use Telltale Valve 110 to verify isolation. | |
| N | Deaerator Drain to Condenser | 2FWC-BV-86 |
| C | Deaerator Drain to Condenser | 2FWC-BV-26 |
| | Use Telltale Valve 105 to verify isolation. | |
| C | Deaerator Drain to Condenser | 2FWC-BV-27 |
| N | Deaerator Drain to Gen Bldg Drain | 2FWC-BV-23 |
| N | Air Preheat Supply | 2FWC-BV-24 |
| C | Recirculation to Condenser | 2FWC-MBV-90 |
| N | Recirculation to Condenser Telltale | 2FWC-BV-110 |
| N | Recirculation to Condenser Drain | 2FWC-BV-105 |

N - Non-critical

C - Critical

## CONDENSATE POLISHING SYSTEM
## P&I DIAGRAMS 2FWD-M2038A AND M2038B

| Class | Description | Valve Number |
|---|---|---|
| | Do not regenerate polishers during test. | |
| C | Makeup to Regen Pumps | 2FWD-BV-121 |
| C | Makeup to Regen Pumps | 2FWD-BV-125 |
| N | Demineralizer Resin Transfer | 2FWD-MBV-72 |
| N | Demineralizer Resin Transfer | 2FWD-MBV-73 |
| N | Demineralizer Resin Transfer | 2FWD-MBV-74 |
| N | Demineralizer Resin Transfer | 2FWD-MBV-75 |
| N | Condensate Demineralizer Drain | 2FWD-MBV-76 |
| N | Condensate Demineralizer Drain | 2FWD-MBV-77 |
| N | Condensate Demineralizer Drain | 2FWD-MBV-78 |
| N | Condensate Demineralizer Drain | 2FWD-MBV-79 |

N - Non-critical

C - Critical

CYCLE MAKEUP AND STORAGE
P&I DIAGRAM 2FWF-M2040

| Class | Description | Valve Number |
|---|---|---|
| N | Low-Pressure Heater Drains | 2FWF-BV-66 |

N - Non-critical

C - Critical

STEAM CYCLE SAMPLING AND ANALYSIS
P&I DIAGRAM 2SAC-M2054A

| Class | Description | Valve Number |
|---|---|---|
| N | Sample No. 1 | 2SAC-BV-17 |
| N | Sample No. 1 | 2SAC-BV-5 |
| N | Sample No. 1 | 2SAC-BV-30 |
| N | Sample No. 2 | 2SAC-BV-6 |
| N | Sample No. 3 | 2SAC-BV-19 |
| N | Sample No. 3 | 2SAC-BV-7 |
| N | Sample No. 3 | 2SAC-BV-32 |
| N | Sample No. 4 | 2SAC-BV-20 |
| N | Sample No. 4 | 2SAC-BV-8 |
| N | Sample No. 4 | 2SAC-BV-33 |
| N | Sample No. 5 | 2SAC-BV-21 |
| N | Sample No. 5 | 2SAC-BV-9 |
| N | Sample No. 5 | 2SAC-BV-34 |
| N | Sample No. 6 | 2SAC-BV-22 |
| N | Sample No. 6 | 2SAC-BV-10 |
| N | Sample No. 6 | 2SAC-BV-35 |
| N | Sample No. 7 | 2SAC-BV-23 |
| N | Sample No. 7 | 2SAC-BV-11 |
| N | Sample No. 7 | 2SAC-BV-36 |
| N | Sample No. 8 | 2SAC-BV-1 |
| N | Sample No. 8 | 2SAC-BV-12 |
| N | Sample No. 8 | 2SAC-BV-24 |
| N | Sample No. 8 | 2SAC-BV-37 |
| N | Sample No. 9 | 2SAC-BV-2 |
| N | Sample No. 10 | 2SAC-BV-13 |
| N | Sample No. 11 | 2SAC-BV-26 |
| N | Sample No. 11 | 2SAC-BV-14 |
| N | Sample No. 11 | 2SAC-BV-39 |
| N | Sample No. 12 | 2SAC-BV-15 |
| N | Sample No. 13 | 2SAC-BV-3 |

STEAM CYCLE SAMPLING AND ANALYSIS (Continued)
P&I DIAGRAM 2SAC-M2054A

| Class | Description | Valve Number |
|---|---|---|
| N | Sample No. 14 | 2SAC-BV-4 |
| N | Sample No. 14 | 2SAC-BV-16 |
| N | Sample No. 14 | 2SAC-BV-26 |
| N | Sample No. 14 | 2SAC-BV-41 |
| N | Sample Recovery Pump Suction | 2SAC-BV-107 |
| N | Sample Recovery Pump Discharge | 2SAC-BV-110 |

N - Non-critical

C - Critical

GENERATION BUILDING SPACE CONDITIONING
P&I DIAGRAM 2SCA-M2056A

| Class | Description | Valve Number |
|---|---|---|
| N | Space Conditioning Drain | 2SGA-BV-429 |

N - Non-critical

C - Critical

STEAM GENERATOR SYSTEM
P&I DIAGRAM 2SGA-M2063A

| Class | Description | Valve Number |
|---|---|---|
| N | Superheat Bypass to Condenser | 2SGA-BV-136 |
| | Use Telltale Valves 165 and 166 to verify isolation. | |
| N | Superheat Bypass to Condenser | 2SGA-BV-138 |
| N | Superheat Bypass to Condenser | 2SGA-BV-169 |
| | Use Telltale Valves 121 and 218 to verify isolation. | |
| N | Superheat Bypass to Condenser | 2SGA-BV-170 |
| N | Superheat Bypass to Reheat | 2SGA-MBV-135 |
| N | Superheat Bypass to Reheat | 2SGA-BV-125 |
| N | Superheat Bypass to Reheat | 2SGA-ACV-134 |
| N | Superheat Bypass to Reheat | 2SGA-MUV-133 |
| N | Boiler Soot Blowing Steam Supply | 2SGA-BV-141 |
| C | Boiler Soot Blowing Steam Supply | 2SGA-MBV-142 |
| N | AH Soot Blowing Steam Supply | 2SGA-BV-139 |
| C | AH Soot Blowing Steam Supply | 2SGA-MBV-140 |
| N | Boiler Soot Blowing Steam Supply | 2SGA-BV-143 |
| C | Boiler Soot Blowing Steam Supply | 2SGA-MBV-144 |
| N | Combustion Gas Reheater Soot Blowing Steam Supply | 2SGA-BV-17 |
| | Use Temperature Indicator 1CCD-TI-120 to verify isolation. | |
| N | Combustion Gas Reheater Soot Blowing Steam Supply | 2SGA-MBV-24 |
| N | Steam Supply to Aux Steam Header | 2SGA-BV-10 |
| N | Steam Trap No. 2 | 2SGA-BV-195 |
| N | Steam Supply to Aux Steam Header | 2SGA-MBV-194 |
| | Use Telltale Valves 203 and 204 to verify isolation. | |
| N | Secondary Superheater Outlet Header | 2SGI-BV-1 |
| N | Secondary Superheater Outlet Header | 2SGI-BV-2 |

STEAM GENERATOR SYSTEM (Continued)
P&I DIAGRAM 2SGA-M2063A

| Class | Description | Valve Number |
|---|---|---|
| N | Secondary Superheater Platen Outlet Header | 2SGI-ACV-29 |
| N | Secondary Superheater Platen Outlet Header | 2SGI-ACV-30 |

N - Non-critical

C - Critical

STEAM GENERATOR SYSTEM
P&I DIAGRAM 2SGA-M2063B

| Class | Description | Valve Number |
|---|---|---|
| N | Gauge Glass LG-1 Drain | 2SGA-BV-11 |
| N | Gauge Glass LG-1 Drain | 2SGA-BV-12 |
| N | Gauge Glass LG-1 Drain | 2SGA-BV-207 |
| N | Gauge Glass LG-3 Drain | 2SGA-BV-25 |
| N | Gauge Glass LG-3 Drain | 2SGA-BV-26 |
| N | Gauge Glass LG-2 Drain | 2SGA-BV-18 |
| N | Gauge Glass LG-2 Drain | 2SGA-BV-208 |
| N | Gauge Glass LG-2 Drain | 2SGA-BV-19 |
| N | Future Sample | 2SGA-BV-54 |
| N | Drain to Blowdown Header | 2SGA-BV-31 |
| N | Drain to Blowdown Header | 2SGA-BV-32 |
| C | Continuous Blowdown | 2SGA-MBV-4 |
| C | Continuous Blowdown | 2SGA-BV-3 |
| N | To Auxiliary Steam Supply | 2SGA-BV-1 |
| N | To Auxiliary Steam Supply | 2SGA-MBV-2 |
| | Use Telltale Valves 206 and 205 to verify isolation. | |
| N | Steam Supply to Aux Steam Header Trap No. 3 | 2SGA-BV-199 |
| C | Sample No. 13 | 2SGA-BV-172 |

N - Non-critical

C - Critical

AIR PREHEAT SYSTEM
P&I DIAGRAM 2SGC-M2065

| Class | Description | Valve Number |
|---|---|---|
| N | Air Preheat Pumps Bypass | 2SGC-BV-119 |
| N | Air Preheat Pumps Inlet | 2SGC-BV-113 |
| N | Air Preheat Pumps Inlet | 2SGC-BV-114 |
| N | Air Preheat Return to Condenser | 2SGC-BV-122 |
| N | Air Preheat Recirculation | 2SGC-BV-123 |
| N | Air Preheat Return to Deaerator | 2SGC-BV-140 |
| N | Air Preheat Return to Deaerator Telltale | 2SGC-BV-148 |
| N | Air Preheat Return to Condenser | 2SGC-BV-141 |
| N | Air Preheat Return to Condenser Telltale | 2SGC-BV-149 |
| N | Air Preheat Emergency Return to Condenser | 2SGC-BV-137 |
| N | Air Preheat Emergency Return to Condenser | 2SGC-BV-139 |
| N | Air Preheat Emergency Return to Condenser Drain | 2SGC-BV-166 |
| N | Air Preheat Emergency Return to Condenser | 2SGC-BV-130 |
| N | Air Preheat Emergency Return to Condenser | 2SGC-BV-131 |

N - Non-critical

C - Critical

BOILER VENTS AND DRAINS SYSTEM
P&I DIAGRAM 2SGF-M2068

DRAINS

| Class | Description | Valve Number |
|---|---|---|
| N | Lwr Convection Pass Header | 2SGF-BV-28 |
| N | Lwr Convection Pass Header | 2SGF-MBV-29 |
| N | Economizer Inlet Header | 2SGF-BV-30 |
| N | Economizer Inlet Header | 2SGF-BV-31 |
| N | Reheater Inlet Header | 2SGF-BV-33 |
| N | Reheater Inlet Header | 2SGF-BV-34 |
| N | Lwr Convection Pass Header | 2SGF-BV-35 |
| N | Lwr Convection Pass Header | 2SGF-MBV-36 |
| N | Reheater Outlet Header | 2SGF-BV-37 |
| N | Reheater Outlet Header | 2SGF-BV-38 |
| N | Reheater Outlet Header | 2SGF-BV-39 |
| N | Reheater Outlet Header | 2SGF-BV-40 |
| N | Secondary Superheater Outlet Header | 2SGF-BV-41 |
| N | Secondary Superheater Outlet Header | 2SGF-MBV-42 |
| N | Secondary Superheater Inter Inlet Header | 2SGF-BV-43 |
| N | Secondary Superheater Inter Inlet Header | 2SGF-MBV-44 |
| N | Secondary Superheater Inter Inlet Header | 2SGF-BV-45 |
| N | Secondary Superheater Inter Inlet Header | 2SGF-MBV-46 |
| N | Drum Feed Header | 2SGF-BV-47 |
| N | Drum Feed Header | 2SGF-BV-48 |
| N | Secondary Superheater Platen Inlet Header | 2SGF-BV-49 |
| N | Secondary Superheater Platen Inlet Header | 2SGF-MBV-50 |
| N | Roof Inlet Header | 2SGF-BV-51 |
| N | Roof Inlet Header | 2SGF-MBV-52 |
| N | Drum Feed Header | 2SGF-BV-53 |
| N | Drum Feed Header | 2SGF-BV-54 |
| N | Lwr Convection Pass Header | 2SGF-BV-55 |
| N | Lwr Convection Pass Header | 2SGF-MBV-56 |
| N | Lwr Convection Pass Header | 2SGF-BV-57 |

BOILER VENTS AND DRAINS SYSTEM (Continued)
P&I DIAGRAM 2SGF-M2068

DRAINS

| Class | Description | Valve Number |
|---|---|---|
| N | Lwr Convection Pass Header | 2SGF-MBV-58 |
| N | Drum West End | 2SGF-BV-59 |
| | Drum West End | 2SGF-BV-60 |
| N | Drum West End | 2SGF-BV-61 |
| N | Drum West End | 2SGF-BV-62 |
| N | Drum West End | 2SGF-BV-63 |
| N | Drum West End | 2SGF-BV-64 |
| N | Downcomer Drain Manifold | 2SGF-BV-65 |
| N | Downcomer Drain Manifold | 2SGF-MBV-66 |
| N | Drum East End | 2SGF-BV-67 |
| N | Drum East End | 2SGF-BV-68 |
| N | Drum East End | 2SGF-BV-69 |
| N | Drum East End | 2SGF-BV-70 |

VENTS

| | | |
|---|---|---|
| N | Economizer Discharge Line | 2SGF-BV-17 |
| N | Primary Superheater Outlet Header | 2SGF-MBV-19 |
| N | Secondary Superheater Platen Outlet Header | 2SGF-MBV-22 |
| N | Drum West End | 2SGF-MBV-10 |
| N | Drum East End | 2SGF-MBV-14 |
| N | Primary Superheater Outlet Header | 2SGF-MBV-24 |
| N | Economizer Discharge Line | 2SGF-BV-26 |

N - Non-critical

C - Critical

MAIN STEAM SYSTEM
P&I DIAGRAM 2SGG-M2069

| Class | Description | Valve Number |
|---|---|---|
| C | Main Steam Vent to Atmosphere | 2SGG-MBV-21 |
| C | Fill Line For Superheater Hydro Test | 2SGG-BV-61 |
| C | Main Steam to BFPT 1A | 2SGG-MBV-9 |
| C | Main Steam to BFPT 1B | 2SGG-MBV-10 |
| | Use temperature measurements at TW-13 and TW-14 to verify isolation. | |
| N | Main Steam Warming Line | 2SGG-MBV-17 |
| N | Main Steam Warming Line | 2SGG-MCV-18 |
| N | Main Steam Drain to Blowdown Tank | 2SGG-MBV-13 |
| N | Main Steam Drain to Blowdown Tank | 2SGG-MBV-14 |
| N | Main Steam to BFPT 1A Bypass | 2SGG-BV-23 |
| N | Main Steam to BFPT 1B Bypass | 2SGG-BV-24 |
| N | Main Steam Drain to Condenser | 2SGG-MBV-25 |
| N | Main Steam Drain to Condenser | 2SGG-MBV-26 |
| N | BFPT Main Steam Drain to Blowdown Tank | 2SGG-MBV-11 |
| N | BFPT Main Steam Drain to Blowdown Tank | 2SGG-MBV-12 |
| N | BFPT Main Steam Drain to Condenser | 2SGG-MBV-55 |
| N | BFPT Main STeam Drain to Condenser | 2SGG-MBV-56 |
| N | Condensate to Desuperheater | 2SGG-ACV-59 |
| N | Main Steam Line Warming Desuperheater | 2SGG-BV-58 |
| N | Main Steam Line Warming Desuperheater | 2SGG-MCV-18 |
| N | Sample No. 14 | 2SGG-BV-15 |
| N | Sample No. 14 | 2SGG-BV-16 |
| N | Condensate to Warming Desuperheater | 2SGG-BV-60 |

N - Non-critical

C - Critical

SOOT BLOWING
P&I DIAGRAM 2SGI-M2070

| Class | Description | Valve Number |
|---|---|---|
| N | Main Steam to Soot Blowers | 2SGI-ACV-3 |
| N | Main Steam to Soot Blowers | 2SGI-ACV-4 |
| N | Main Steam to Soot Blowers | 2SGI-ACV-25 |
| N | Main Steam to Soot Blowers | 2SGI-ACV-26 |
| N | Soot Blowers Steam to HP Heater Extraction | 2SGI-MBV-35 |
| N | Soot Blowers Steam to HP Heater Extraction | 2SGI-MBV-178 |

N - Non-critical

C - Critical

HOT/COLD REHEAT SYSTEM
P&I DIAGRAM 2SGJ-M2071

| Class | Description | Valve Number |
|---|---|---|
| N | Hot Reheat Drains | 2SGJ-MBV-16 |
| N | Hot Reheat Drains | 2SGJ-MBV-14 |
| N | Cold Reheat Drains | 2SGJ-MBV-18 |
| N | Cold Reheat Drains | 2SGJ-BV-56 |
| N | Cold Reheat Drains | 2SGJ-BV-57 |
| N | Reheat Desuperheater Spray | 2SGJ-ACV-58 |
| N | Reheat Desuperheater Spray | 2SGJ-ACV-59 |
| N | Reheat Desuperheater Spray | 2SGJ-ACV-66 |
| N | Reheat Desuperheater Spray | 2SGJ-ACV-67 |
| N | CNDS to Cold Reheat Drain Desuperheater | 2SGJ-BV-90 |

N - Non-critical

C - Critical

HIGH-PRESSURE EXTRACTION SYSTEM
P&I DIAGRAM 2TEA-M2073

| Class | Description | Valve Number |
|---|---|---|
| N | Aux Steam to BFPT | 2TEA-MBV-118 |

N - Non-critical

C - Critical

EXTRACTION TRAPS AND DRAINS SYSTEM
P&I DIAGRAM 2TEC-M2075

| Class | Description | Valve Number |
|---|---|---|
| C | HP Heaters 8A and 8B Extr Drain | 2TEC-BV-73 |
| C | HP Heaters 8A and 8B Extr Drain | 2TEC-BV-75 |
| C | HP Heater 8A Extr Drain | 2TEC-BV-79 |
| C | HP Heater 8A Extr Drain | 2TEC-BV-81 |
| C | HP Heater 6B Extr Drain | 2TEC-BV-105 |
| N | LP Heater 3 Extr Drain | 2TEC-BV-35 |
| N | HP Heaters 8A and 8B Extr Drain | 2TEC-ACV-74 |
| N | HP Heater 8A Extr Drain | 2TEC-ACV-80 |
| C | HP Heater 8B Extr Drain | 2TEC-ACV-86 |
| C | HP Heaters 6A and 6B Extr Drain | 2TEC-ACV-92 |
| C | HP Heater 6A Extr Drain | 2TEC-ACV-98 |
| C | HP Heater 6B Extr Drain | 2TEC-ACV-104 |
| C | BFPT 1B Extr Drain | 2TEC-ACV-140 |
| C | BFPT 1A Extr Drain | 2TEC-ACV-134 |
| C | Deaerator Heater 5 Extr Drain | 2TEC-ACV-128 |
| C | BFPT 1A and 1B Extr Drain | 2TEC-ACV-122 |
| C | Deaerator Heater 5 Extr Drain | 2TEC-ACV-116 |
| C | Deaerator Heater 5 Extr Drain | 2TEC-ACV-110 |
| C | BFPT 1A Extr Drain | 2TEC-ACV-146 |
| C | BFPT 1B Extr Drain | 2TEC-ACV-152 |
| C | LP Heater 4 Extr Drain | 2TEC-BV-65 |
| N | LP Heater 4 Extr Drain | 2TEC-BV-67 |
| N | Miscellaneous Drains Rcvr Tank | 2TEC-BV-163 |
| | Vent and overflow should be checked for leaks. | |
| N | LP Heater 2 Extr Drain | 2TEC-ACV-2 |
| N | LP Heater 2 Extr Drain | 2TEC-ACV-6 |
| N | LP Heater 3 Extr Drain | 2TEC-ACV-10 |
| N | LP Heater 3 Extr Drain | 2TEC-ACV-14 |
| N | LP Heater 4 Extr Drain | 2TEC-ACV-18 |
| N | LP Heater 4 Extr Drain | 2TEC-ACV-22 |
| N | LP Heater 2 Extr Drain | 2TEC-ACV-50 |

EXTRACTION TRAPS AND DRAINS SYSTEM (Continued)
P&I DIAGRAM 2TEC-M2075

| Class | Description | Valve Number |
|---|---|---|
| N | LP Heater 2 Extr Drain | 2TEC-ACV-54 |
| N | LP Heater 3 Extr Drain | 2TEC-ACV-58 |
| N | LP Heater 3 Extr Drain | 2TEC-ACV-62 |
| N | LP Heater 4 Extr Drain | 2TEC-ACV-66 |
| N | LP Heater 4 Extr Drain | 2TEC-ACV-70 |
| N | LP Heater 2 Extr Drain | 2TEC-ACV-26 |
| N | LP Heater 2 Extr Drain | 2TEC-ACV-30 |
| N | LP Heater 3 Extr Drain | 2TEC-ACV-34 |
| N | LP Heater 3 Extr Drain | 2TEC-ACV-38 |
| N | LP Heater 4 Extr Drain | 2TEC-ACV-42 |
| N | LP Heater 4 Extr Drain | 2TEC-ACV-46 |
| N | LP Heater 4 Extr Drain | 2TEC-BV-39 |
| N | LP Heater 4 Extr Drain | 2TEC-BV-43 |
| N | LP Heater 4 Extr Drain | 2TEC-BV-47 |
| C | LP Heater 3 Extr Drain | 2TEC-BV-11 |
| N | LP Heater 3 Extr Drain | 2TEC-BV-15 |
| C | LP Heater 4 Extr Drain | 2TEC-BV-19 |
| N | LP Heater 4 Extr Drain | 2TEC-BV-23 |
| N | LP Heater 3 Extr Drain | 2TEC-BV-59 |
| N | LP Heater 3 Extr Drain | 2TEC-BV-63 |
| N | LP Heater 2 Extr Drain | 2TEC-BV-27 |
| N | LP Heater 2 Extr Drain | 2TEC-BV-31 |
| N | LP Heater 2 Extr Drain | 2TEC-BV-3 |
| N | LP Heater 2 Extr Drain | 2TEC-BV-7 |
| N | LP Heater 2 Extr Drain | 2TEC-BV-51 |
| N | LP Heater 2 Extr Drain | 2TEC-BV-55 |

NOTE: Isolation of the extraction drains should be verified by checking the surface temperature of the drain pipe.

N - Non-critical

C - Critical

HIGH-PRESSURE HEATER DRAINS
P&I DIAGRAM 2TED-M2076

| Class | Description | Valve Number |
|---|---|---|
| N | HP Heater Drain Return | 2TED-ACV-13 |
| N | HP Heater Drain Return | 2TED-ACV-14 |
| C | HP Heater Drain to Condenser | 2TED-BV-19 |
| C | HP Heater Drain to Condenser | 2TED-BV-20 |
| C | HP Heater Drain to Condenser | 2TED-BV-21 |
| C | HP Heater Drain to Condenser | 2TED-BV-22 |
| C | HP Heater Drain to Condenser | 2TED-BV-27 |
| C | HP Heater Drain to Condenser | 2TED-BV-28 |
| C | HP Heater Drain to Condenser | 2TED-BV-29 |
| C | HP Heater Drain to Condenser | 2TED-BV-30 |
| C | HP Heater Drain to Condenser | 2TED-BV-35 |
| C | HP Heater Drain to Condenser | 2TED-BV-36 |
| C | HP Heater Drain to Condenser | 2TED-BV-37 |
| C | HP Heater Drain to Condenser | 2TED-BV-38 |

N - Non-critical

C - Critical

LOW-PRESSURE HEATER DRAINS SYSTEM
P&I DIAGRAM 2TEE-M2077

| Class | Description | Valve Number |
|---|---|---|
| C | LP Htr Drains to Condenser | 2TEE-BV-9 |
| C | LP Htr Drains to Condenser | 2TEE-BV-11 |
| C | LP Htr Drains to Condenser | 2TEE-BV-13 |
| C | LP Htr Drains to Condenser | 2TEE-BV-15 |
| C | LP Htr Drains to Condenser | 2TEE-BV-17 |
| C | LP Htr Drains to Condenser | 2TEE-BV-19 |
| C | LP Htr Drains to Condenser | 2TEE-BV-21 |
| C | LP Htr Drains to Condenser | 2TEE-BV-22 |
| N | LP Htr Drains to Cycle Makeup | 2TEE-BV-129 |

N - Non-critical

C - Critical

HEATER VENTS AND MISCELLANEOUS DRAINS SYSTEM
P&I DIAGRAMS 2TEF-M2078A AND M2078B

Relief valves, vents, and drains should be checked and isolated in accordance with previously discussed procedures.

TURBINE SYSTEM
P&I DIAGRAM 2TGA-M2079

| Class | Description | Valve Number |
|---|---|---|
| N | Ventilator Valve | 2TGA-ABV-2 |
| N | Condenser Hood Sprays | 2TGA-BV-5 |

N - Non-critical

C - Critical

TURBINE SEALS AND DRAINS SYSTEM
P&I DIAGRAMS 2TGC-M2080A AND M2080B

| Class | Description | Valve Number |
|---|---|---|
| C | Main Steam Supply | 2TGC-BV-10* |
| N | Main Steam Supply | 2TGC-MBV-3* |
| N | Main Steam Supply | 2TGC-MBV-2* |
| N | Main Steam Supply | 2TGC-ACV-1* |
| N | Auxiliary Steam Supply | 2TGC-MBV-6 |
| N | Auxiliary Steam Supply | 2TGC-ACV-5 |
| N | Condensate to Steam Seal Desuperheater | 2TGC-BV-25 |
| N | Auxiliary Steam to Cold Reheat | 2TGC-MBV-16 |
| N | Auxiliary Steam to Cold Reheat | 2TGC-BV-58 |
| N | Reheat Valve Drain | 2TGC-MBV-31 |
| N | Reheat Valve Drain | 2TGC-MBV-32 |
| N | Control Valve/Stop Valve Drains | 2TGC-MBV-33 |
| N | Control Valve/Stop Valve Drains | 2TGC-MBV-34 |
| N | Control Valve/Stop Valve Drains | 2TGC-MBV-35 |
| N | Control Valve/Stop Valve Drains | 2TGC-MBV-36 |
| N | Control Valve/Stop Valve Drains | 2TGC-MBV-37 |
| N | Control Valve/Stop Valve Drains | 2TGC-MBV-38 |
| N | Control Valve/Stop Valve Drains | 2TGC-MBV-39 |
| N | Control Valve/Stop Valve Drains | 2TGC-MBV-40 |
| N | Steam Lead Drain | 2TGC-MBV-49 |
| N | HP Turb Leakoff to Steam Seals | 2TGC-ACV-17 |

*Requires full-time operator. Must be opened quickly on a turbine trip.

N - Non-critical

C - Critical

## 5.0 SAMPLE CALCULATIONS

| Variable | Description | Test 6 Value |
|---|---|---|
| TCND | Temperature of Condensate at Flow Section | 295.8 F |
| PCND | Pressure of Condensate at Flow Section | 141.2 psia |
| TAMB | Temperature of Ambient Air | 90.3 F |
| G | Local Acceleration of Gravity | 32.138 $ft/sec^2$ |
| TFWO8 | Temperature of Feedwater out of Feedwater Heater 8 | 551.1 F |
| PFWO8 | Pressure of Feedwater out of Feedwater Heater 8 | 2733.9 psia |
| DPFWN | Differential Pressure Across Feedwater Flow Nozzle | 58.113 psid |
| DPCNDNA | Differential Pressure Across Condensate Flow Nozzle Tap A | 10.290 psid |
| DPCNDNB | Differential Pressure Across Condensate Flow Nozzle Tap B | 10.280 psid |
| TFGRR | Temperature of Flue Gas Reheat Return Water | 232.2 F |
| PFGRR | Pressure of Flue Gas Reheat Return Water | 139.2 psia |
| DPFGRR | Differential Pressure Across Flue Gas Reheat Flow Nozzle | 3.597 psid |
| TL04 | Temperature of Steam Leakage Number 4 | 602.4 F |
| PL04 | Pressure of Steam Leakage Number 4 | 118.3 psia |
| DPL04 | Differential Pressure of Steam Leakage Number 4 | 0.895 psid |
| TL06 | Temperature of Steam Leakage Number 6 | 692 F |
| PL06 | Pressure of Steam Leakage Number 6 | 118.3 psia |
| DPL06 | Differential Pressure of Steam Leakage Number 6 | 4.620 psid |
| TCLGLO | Temperature of IP Rotor Cooling Steam | 818.1 F |
| PCLGLO | Pressure of IP Rotor Cooling Steam | 521.0 psia |
| DPCLGLO | Differential Pressure of IP Rotor Cooling Steam | 19.601 psid |
| TVSLO | Temperature of Valve Stem Leakoff Steam | 886.5 F |
| PVSLO | Pressure of Valve Stem Leakoff Steam | 521.0 psia |
| DPVSLO | Differential Pressure of Valve Stem Leakoff Steam | 0.0 psid |

| Variable | Description | Test 6 Value |
|---|---|---|
| TLO2 | Temperature of Steam Leakage Number 2 | 886.5 F |
| PLO2 | Pressure of Steam Leakage Number 2 | 521.0 psia |
| PCLO2 | Packing Constant of Steam Leakage Number 2 | 50 |
| TLO3 | Temperature of Steam Leakage Number 3 | 971.9 F |
| PLO3 | Pressure of Steam Leakage Number 3 | 1,927.3 psia |
| PCLO3 | Packing Constant of Steam Leakage Number 3 | 540 |
| TLO5 | Temperature of Steam Leakage Number 5 | 582.4 F |
| PLO5 | Pressure of Steam Leakage Number 5 | 120.7 psia |
| PCLO5 | Packing Constant of Steam Leakage Number 5 | 800 |
| TLO7 | Temperature of Steam Leakage Number 7 | 682.6 F |
| PLO7 | Pressure of Steam Leakage Number 7 | 122.5 psia |
| PCLO7 | Packing Constant of Steam Leakage Number 7 | 980 |
| TLO8 | Temperature of Steam Leakage Number 8 | 635.5 F |
| PLO8 | Pressure of Steam Leakage Number 8 | 120.7 psia |
| PCLO8 | Packing Constant of Steam Leakage Number 8 | 550 |
| TLO9 | Temperature of Steam Leakage Number 9 | 645.7 F |
| PLO9 | Pressure of Steam Leakage Number 9 | 122.5 psia |
| PCLO9 | Packing Constant of Steam Leakage Number 9 | 550 |
| TDV1A | Temperature of Steam Seals to Heater 1A | 654.1 F |
| PDV1A | Pressure of Steam Seals to Heater 1A | 5.031 psia |
| DPDV1A | Differential Pressure of Steam Seals to Heater 1A | 0.037 psid |
| TCVCND | Temperature of Steam Seals to Condenser | 654 F |
| PDVCND | Pressure of Steam Seals to Condenser | 2.117 psia |
| DPDVCND | Differential Pressure of Steam Seals to Condenser | 0.0 psid |
| TEXTBFPTA | Temperature of Extraction Steam at Boiler Feed Pump Turbine A | 619.2 F |
| PEXTBFPTA | Pressure of Extraction Steam at Boiler Feed Pump Turbine A | 119.3 psia |
| DPEXTBFPTA | Differential Pressure of Extraction Steam at Boiler Feed Pump Turbine A | 6.216 psid |
| TEXTBFPTB | Temperature of Extraction Steam at Boiler Feed Pump Turbine B | 619.1 F |
| PEXTBFPTB | Pressure of Extraction Steam at Boiler Feed Pump Turbine B | 119.3 psia |

| Variable | Description | Test 6 Value |
|---|---|---|
| DPEXTBFPTB | Differential Pressure of Extraction Steam at Boiler Feed Pump Turbine B | 6.813 psid |
| SPBFPTA | Speed of Boiler Feed Pump Turbine A | 5,292.6 rpm |
| HPBFPTA | Horsepower of Boiler Feed Pump Turbine A | 12,347 hp |
| PFWPO1A | Pressure of Boiler Feed Pump Discharge A | 2,920.2 psia |
| TFWPO1A | Temperature of Boiler Feed Pump Discharge A | 345.9 F |
| PFWPI | Pressure of Boiler Feed Pump Inlet A | 318.6 psia |
| TFWPI | Temperature of Boiler Feed Pump Inlet A | 340.0 F |
| TCNDPD | Temperature of Condensate Pump Discharge | 126.6 F |
| PCNDPD | Pressure of Condensate Pump Discharge | 411.8 psia |
| PEXT8A | Pressure of Feedwater Heater 8A Extraction Steam | 1,064.5 psia |
| TEXT8A | Temperature of Feedwater Heater 8A Extraction Steam | 787.9 F |
| PEXT8B | Pressure of Feedwater Heater 8B Extraction Steam | 1,060.7 psia |
| TEXT8B | Temperature of Feedwater Heater 8B Extraction Steam | 788.2 F |
| PEXT7A | Pressure of Feedwater Heater 7A Extraction Steam | 557.0 psia |
| TEXT7A | Temperature of Feedwater Heater 7A Extraction Steam | 618.0 F |
| PEXT7B | Pressure of Feedwater Heater 7B Extraction Steam | 557.0 psia |
| TEXT7B | Temperature of Feedwater Heater 7B Extraction Steam | 618.5 F |
| PEXT6A | Pressure of Feedwater Heater 6A Extraction Steam | 230.8 psia |
| TEXT6A | Temperature of Feedwater Heater 6A Extraction Steam | 803.3 F |
| PEXT6B | Pressure of Feedwater Heater 6B Extraction Steam | 229.0 psia |
| TEXT6B | Temperature of Feedwater Heater 6B Extraction Steam | 800.8 F |
| PEXT5 | Pressure of Deaerating Heater 5 Extraction Steam | 118.3 psia |
| TEXT5 | Temperature of Deaerating Heater 5 Extraction Steam | 619.6 F |

| Variable | Description | Test 6 Value |
|---|---|---|
| PEXT4 | Pressure of Feedwater Heater 4 Extraction Steam | 63.38 psia |
| TEXT4 | Temperature of Feedwater Heater 4 Extraction Steam | 515.8 F |
| PEXT3 | Pressure of Feedwater Heater 3 Extraction Steam | 37.94 psia |
| TEXT3 | Temperature of Feedwater Heater 3 Extraction Steam | 414.8 F |
| PEXT2 | Pressure of Feedwater Heater 2 Extraction Steam | 11.05 psia |
| TEXT2 | Temperature of Feedwater Heater 2 Extraction Steam | 233.9 F |
| PEXT1A | Pressure of Feedwater Heater 1A | 4.880 psia |
| PEXT1B | Pressure of Feedwater Heater 1B | 4.784 psia |
| PEXT1C | Pressure of Feedwater Heater 1C | 5.476 psia |
| PFWECON | Pressure of Feedwater at Economizer | 2,734 psia |
| PCNDO4 | Pressure of Condensate out of Heater 4 | 174.5 psia |
| TDR8A | Temperature of Feedwater Heater 8A Drains | 486.4 F |
| TDR8B | Temperature of Feedwater Heater 8B Drains | 485.6 F |
| TDR7A | Temperature of Feedwater Heater 7A Drains | 404.6 F |
| TDR7B | Temperature of Feedwater Heater 7B Drains | 402.8 F |
| TDR6A | Temperature of Feedwater Heater 6A Drains | 353.2 F |
| TDR6B | Temperature of Feedwater Heater 6B Drains | 353.4 F |
| TDR4 | Temperature of Feedwater Heater 4 Drains | 269.0 F |
| TDR3 | Temperature of Feedwater Heater 3 Drains | 205.3 F |
| TDR2 | Temperature of Feedwater Heater 2 Drains | 167.9 F |
| TDR1 | Temperature of Feedwater Heater 1 Drains | 161.4 F |
| TFWO8A | Temperature of Feedwater out of Feedwater Heater 8A | 551.8 F |
| TFWO7A | Temperature of Feedwater out of Feedwater Heater 7A | 479.2 F |
| TFWO6A | Temperature of Feedwater out of Feedwater Heater 6A | 395.3 F |
| TFWO8B | Temperature of Feedwater out of Feedwater Heater 8B | 552.5 F |
| TFWO7B | Temperature of Feedwater out of Feedwater Heater 7B | 478.4 F |

| Variable | Description | Test 6 Value |
|---|---|---|
| TFWO6B | Temperature of Feedwater out of Feedwater Heater 6B | 394.5 F |
| TFWO5 | Temperature of Feedwater out of Deaerating Heater 5 | 340.4 F |
| TCNDO4 | Temperature of Condensate out of Feedwater Heater 4 | 296.6 F |
| TCNDO3 | Temperature of Condensate out of Feedwater Heater 3 | 264.2 F |
| TCNDO2 | Temperature of Condensate out of Feedwater Heater 2 | 195.8 F |
| TCNDO1A | Temperature of Condensate out of Feedwater Heater 1A | 160.9 F |
| TCNDO1B | Temperature of Condensate out of Feedwater Heater 1B | 160.1 F |
| TCNDO1C | Temperature of Condensate out of Feedwater Heater 1C | 160.7 F |
| TCNDI4 | Temperature of Condensate into Feedwater Heater 4 | 264.2 F |
| TCNDI3 | Temperature of Condensate into Feedwater Heater 3 | 196.6 F |
| TCNDI2 | Temperature of Condensate into Feedwater Heater 2 | 160.0 F |
| TCNDI1 | Temperature of Condensate into Feedwater Heater 1 | 133.4 F |
| TCNDIDC | Temperature of Condensate into Drain Cooler | 127.6 F |
| PCNDI5 | Pressure of Condensate into Deaerator | 141.2 psia |
| PCNDDCI | Pressure of Condensate into Drain Cooler | 222.2 psia |
| PEXTS4 | Pressure of Steam at Stage 4 Extraction | 1,075.4 psia |
| TEXTS4 | Temperature of Steam at Stage 4 Extraction | 790.2 F |
| PCRH | Pressure of Cold Reheat Steam | 571.5 psia |
| TCRH | Temperature of Cold Reheat Steam | 619.1 F |
| PEXTS11 | Pressure of Steam at Stage 11 Extraction | 231.6 psia |
| TEXTS11 | Temperature of Steam at Stage 11 Extraction | 803.5 F |
| PEXTS14 | Pressure of Steam at Stage 14 Extraction | 121.6 psia |
| TEXTS14 | Temperature of Steam at Stage 14 Extraction | 622.2 F |
| PEXTS15 | Pressure of Steam at Stage 15 Extraction | 64.6 psia |
| TEXTS15 | Temperature of Steam at Stage 15 Extraction | 526.6 F |
| PEXTS16 | Pressure of Steam at Stage 16 Extraction | 39.33 psia |

| Variable | Description | Test 6 Value |
|---|---|---|
| TEXTS16 | Temperature of Steam at Stage 16 Extraction | 422.4 F |
| PEXTS18 | Pressure of Steam at Stage 18 Extraction | 11.52 psia |
| TEXTS18 | Temperature of Steam at Stage 18 Extraction | 233.8 F |
| PEXTS19 | Pressure of Steam at Stage 19 Extraction | 4.943 psia |
| PHDA | Pressure of Condenser Hood A | 2.056 psia |
| PHDB | Pressure of Condenser Hood B | 1.980 psia |
| PHDC | Pressure of Condenser Hood C | 1.267 psia |
| TMS | Temperature of Main Steam | 996.5 F |
| PMS | Pressure of Main Steam | 2,394.1 psia |
| THRH | Temperature of Hot Reheat Steam | 1,003.1 F |
| PHRH | Pressure of Hot Reheat Steam | 527.6 psia |
| PHRHB | Pressure of Hot Reheat Steam at IP Turbine Bowl | 521.0 psia |
| PCXO | Pressure of Crossover Steam | 118.6 psia |
| TCXOB | Temperature of Crossover Steam at LP Turbine Bowl | 618.8 F |
| PCNDS | Pressure of Condenser, Specified | 1.5 in. Hg |
| DPBFP1A | Differential Pressure of Seal Injection Water to Boiler Feed Pump 1A | 3.095 psid |
| DPBFP1B | Differential Pressure of Seal Injection Water to Boiler Feed Pump 1B | 1.119 psid |
| DPBFP1C | Differential Pressure of Seal Injection Water to Boiler Feed Pump 1C | 11.162 psid |
| DPBFP2A | Differential Pressure of Seal Injection Water to Booster Boiler Feed Pump 2A | 2.468 psid |
| DPBFP2B | Differential Pressure of Seal Injection Water to Booster Boiler Feed Pump 2B | 6.487 psid |
| DPBFP2C | Differential Pressure of Seal Injection Water to Booster Boiler Feed Pump 2C | 6.172 psid |
| TCWOA | Temperature of Circulating Water out of HP Condenser A | 117.9 F |
| TCWOB | Temperature of Circulating Water out of IP Condenser B | 116.2 F |
| TCWOC | Temperature of Circulating Water out of LP Condenser C | 100.5 F |
| TCWIA | Temperature of Circulating Water into HP Condenser A | 100.5 F |

| Variable | Description | Test 6 Value |
|---|---|---|
| TCWIB | Temperature of Circulating Water into IP Condenser B | 86.5 F |
| TCWIC | Temperature of Circulating Water into LP Condenser C | 86.5 F |
| TIME | Time Length of Test | 2 hours |
| PHACNT | Phase A Watt Meter Counts | 20,093 |
| PHBCNT | Phase B Watt Meter Counts | 20,088 |
| PHCCNT | Phase C Watt Meter Counts | 19,818 |
| PHAV | Phase A Secondary Volts | 129.374 |
| PHBV | Phase B Secondary Volts | 129.172 |
| PHCV | Phase C Secondary Volts | 128.565 |
| PHAA | Phase A Secondary Amps | 3.884 |
| PHBA | Phase B Secondary Amps | 3.924 |
| PHCA | Phase C Secondary Amps | 3.911 |
| PDRUM | Boiler Drum Pressure | 2,667.4 psia |

| Variable | Description | Test 6 Calculated Value |
|---|---|---|
| QGEN | Generator Output | 860,776 kW |
| APF | Average Power Factor | 0.9891 |
| VSTD | Specific Volume Water at Standard Conditions | 0.01605 $ft^3/lb_m$ |
| VCND | Specific Volume of Condensate at Flow Section | 0.01740 $ft^3/lb_m$ |
| VAMBC | Specific Volume of Condensate at Ambient Temperature at Flow Section | 0.01610 $ft^3/lb_m$ |
| VFW | Specific Volume of Feedwater at Feedwater Flow Nozzle | 0.021209 $ft^3/lb_m$ |
| VFGR | Specific Volume of Flue Gas Reheat at Flow Nozzle | 0.01685 $ft^3/lb_m$ |
| VLO4 | Specific Volume of Leakoff Steam Number 4 | 5.2507 $ft^3/lb_m$ |
| VLO6 | Specific Volume of Leakoff Steam Number 6 | 5.7218 $ft^3/lb_m$ |
| VCLGLO | Specific Volume of IP Rotor Cooling Steam | 1.4033 $ft^3/lb_m$ |

| Variable | Description | Test 6 Calculated Value |
|---|---|---|
| VVSLO | Specific Volume of Valve Stem Leakoff | 1.490 $ft^3/lb_m$ |
| VLO2 | Specific Volume of Steam Leakage Number 2 | 1.490 $ft^3/lb_m$ |
| VLO5 | Specific Volume of Steam Leakage Number 5 | 5.039 $ft^3/lb_m$ |
| VLO7 | Specific Volume of Steam Leakage Number 7 | 5.478 $ft^3/lb_m$ |
| VLO8 | Specific Volume of Steam Leakage Number 8 | 5.316 $ft^3/lb_m$ |
| VLO9 | Specific Volume of Steam Leakage Number 9 | 5.291 $ft^3/lb_m$ |
| HLO4 | Enthalpy of Steam Leakage Number 4 | 1,329.22 $Btu/lb_m$ |
| HLO6 | Enthalpy of Steam Leakage Number 6 | 1,374.27 $Btu/lb_m$ |
| HLO2 | Enthalpy of Steam Leakage Number 2 | 1,458.48 $Btu/lb_m$ |
| HLO5 | Enthalpy of Steam Leakage Number 5 | 1,318.93 $Btu/lb_m$ |
| HLO7 | Enthalpy of Steam Leakage Number 7 | 1,369.32 $Btu/lb_m$ |
| HLO8 | Enthalpy of Steam Leakage Number 8 | 1,345.70 $Btu/lb_m$ |
| HLO9 | Enthalpy of Steam Leakage Number 9 | 1,350.71 $Btu/lb_m$ |
| VDV1A | Specific Volume of Steam Seals Steam to Heater 1A | 131.75 $ft^3/lb_m$ |
| HDV1A | Enthalpy of Steam Seals to Heater 1A | 1,361.95 $Btu/lb_m$ |
| VEXTBFPTA | Specific Volume of Boiler Feed Pump Turbine A Extraction Steam | 5.2977 $ft^3/lb_m$ |
| VEXTBFPTB | Specific Volume of Boiler Feed Pump Turbine B Extraction Steam | 5.2938 $ft^3/lb_m$ |
| HBFPTTA | Enthalpy of Boiler Feed Pump Turbine A Throttle Steam | 1,337.62 $Btu/lb_m$ |
| VFWPDA | Specific Volume of Feedwater at Boiler Feed Pump A Discharge | 0.017701 $ft^3/lb_m$ |

| Variable | Description | Test 6 Calculated Value |
|---|---|---|
| VFWPIA | Specific Volume of Feedwater at Boiler Feed Pump A Inlet | 0.017853 $ft^3/lb_m$ |
| VCNDPD | Specific Volume of Condensate at Condensate Pump Discharge | 0.01621 $ft^3/lb_m$ |
| HEXT8A | Enthalpy of Feedwater Heater 8A Extraction Steam | 1,377.78 $Btu/lb_m$ |
| HEXT8B | Enthalpy of Feedwater Heater 8B Extraction Steam | 1,378.17 $Btu/lb_m$ |
| HEXT7A | Enthalpy of Feedwater Heater 7A Extraction Steam | 1,304.60 $Btu/lb_m$ |
| HEXT7B | Enthalpy of Feedwater Heater 7B Extraction Steam | 1,304.90 $Btu/lb_m$ |
| HEXT6A | Enthalpy of Feedwater Heater 6A Extraction Steam | 1,425.76 $Btu/lb_m$ |
| HEXT6B | Enthalpy of Feedwater Heater 6B Extraction Steam | 1,424.53 $Btu/lb_m$ |
| HEXT5 | Enthalpy of Feedwater Heater 5 Extraction Steam | 1,337.83 $Btu/lb_m$ |
| HEXT4 | Enthalpy of Feedwater Heater 4 Extraction Steam | 1,290.46 $Btu/lb_m$ |
| HEXT3 | Enthalpy of Feedwater Heater 3 Extraction Steam | 1,243.89 $Btu/lb_m$ |
| HEXT2 | Enthalpy of Feedwater Heater 2 Extraction Steam | 1,162.29 $Btu/lb_m$ |
| HEXT1 | Enthalpy of Feedwater Heater 1 Extraction Steam | 1,090 $Btu/lb_m$ |
| TSEXT8A | Temperature of Feedwater Heater 8A Saturated Steam | 552.22 F |
| TSEXT8B | Temperature of Feedwater Heater 8B Saturated Steam | 551.78 F |
| TSEXT7A | Temperature of Feedwater Heater 7A Saturated Steam | 478.27 F |
| TSEXT7B | Temperature of Feedwater Heater 7B Saturated Steam | 478.27 F |
| TSEXT6A | Temperature of Feedwater Heater 6A Saturated Steam | 394.00 F |
| TSEXT6B | Temperature of Feedwater Heater 6B Saturated Steam | 393.33 F |

| Variable | Description | Test 6 Calculated Value |
|---|---|---|
| TSEXT5 | Temperature of Feedwater Heater 5 Saturated Steam | 340.22 F |
| TSEXT4 | Temperature of Feedwater Heater 4 Saturated Steam | 296.30 F |
| TSEXT3 | Temperature of Feedwater Heater 3 Saturated Steam | 264.17 F |
| TSEXT2 | Temperature of Feedwater Heater 2 Saturated Steam | 197.95 F |
| TSEXT1A | Temperature of Feedwater Heater 1A Saturated Steam | 161.17 F |
| TSEXT1B | Temperature of Feedwater Heater 1B Saturated Steam | 160.34 F |
| TSEXT1C | Temperature of Feedwater Heater 1C Saturated Steam | 166.07 F |
| HDR8A | Enthalpy of Feedwater Heater 8A Drains | 471.72 $Btu/lb_m$ |
| HDR8B | Enthalpy of Feedwater Heater 8B Drains | 470.80 $Btu/lb_m$ |
| HRD7A | Enthalpy of Feedwater Heater 7A Drains | 380.42 $Btu/lb_m$ |
| HDR7B | Enthalpy of Feedwater Heater 7B Drains | 378.47 $Btu/lb_m$ |
| HDR6A | Enthalpy of Feedwater Heater 6A Drains | 325.29 $Btu/lb_m$ |
| HDR6B | Enthalpy of Feedwater Heater 6B Drains | 325.56 $Btu/lb_m$ |
| HDR5 | Enthalpy of Feedwater Heater 5 Drains | 311.68 $Btu/lb_m$ |
| HDR4 | Enthalpy of Feedwater Heater 4 Drains | 237.99 $Btu/lb_m$ |
| HDR3 | Enthalpy of Feedwater Heater 3 Drains | 173.50 $Btu/lb_m$ |
| HDR2 | Enthalpy of Feedwater Heater 2 Drains | 135.84 $Btu/lb_m$ |
| HDR1 | Enthalpy of Feedwater Heater 1 Drains | 129.35 $Btu/lb_m$ |
| HFWO8A | Enthalpy of Feedwater out of Feedwater Heater 8A | 548.25 $Btu/lb_m$ |

| Variable | Description | Test 6 Calculated Value |
|---|---|---|
| HFWO8B | Enthalpy of Feedwater out of Feedwater Heater 8B | 549.13 $Btu/lb_m$ |
| HFWO7A | Enthalpy of Feedwater out of Feedwater Heater 7A | 463.97 $Btu/lb_m$ |
| HFWO7B | Enthalpy of Feedwater out of Feedwater Heater 7B | 463.04 $Btu/lb_m$ |
| HFWO6A | Enthalpy of Feedwater out of Feedwater Heater 6A | 373.42 $Btu/lb_m$ |
| HFWO6B | Enthalpy of Feedwater out of Feedwater Heater 6B | 372.56 $Btu/lb_m$ |
| HFWI6A | Enthalpy of Feedwater into Feedwater Heater 6A | 321.76 $Btu/lb_m$ |
| HFWI6B | Enthalpy of Feedwater into Feedwater Heater 6B | 321.49 $Btu/lb_m$ |
| HFWO5 | Enthalpy of Feedwater out of Feedwater Heater 5 | 311.68 $Btu/lb_m$ |
| HCNDO4 | Enthalpy of Condensate out of Feedwater Heater 4 | 266.42 $Btu/lb_m$ |
| HCNDO3 | Enthalpy of Condensate out of Feedwater Heater 3 | 233.29 $Btu/lb_m$ |
| HCNDO2 | Enthalpy of Condensate out of Feedwater Heater 2 | 164.30 $Btu/lb_m$ |
| HCNDO1A | Enthalpy of Condensate out of Feedwater Heater 1A | 129.32 $Btu/lb_m$ |
| HCNDO1B | Enthalpy of Condensate out of Feedwater Heater 1B | 128.53 $Btu/lb_m$ |
| HCNDO1C | Enthalpy of Condensate out of Feedwater Heater 1C | 129.16 $Btu/lb_m$ |
| HCNDI5 | Enthalpy of Condensate into Feedwater Heater 5 | 265.64 $Btu/lb_m$ |
| HCNDI4 | Enthalpy of Condensate into Feedwater Heater 4 | 233.36 $Btu/lb_m$ |
| HCNDI3 | Enthalpy of Condensate into Feedwater Heater 3 | 165.07 $Btu/lb_m$ |
| HCNDI2 | Enthalpy of Condensate into Feedwater Heater 2 | 128.40 $Btu/lb_m$ |
| HCNDI1 | Enthalpy of Condensate into Feedwater Heater 1 | 101.89 $Btu/lb_m$ |

| Variable | Description | Test 6 Calculated Value |
|---|---|---|
| HEXTS4 | Enthalpy of Stage 4 Extraction Steam | 1,378.64 $Btu/lb_m$ |
| HCRH | Enthalpy of Cold Reheat Steam | 1,304.12 $Btu/lb_m$ |
| HEXTS11 | Enthalpy of Stage 11 Extraction Steam | 1,425.82 $Btu/lb_m$ |
| HEXTS14 | Enthalpy of Stage 14 Extraction Steam | 1,338.93 $Btu/lb_m$ |
| HEXTS15 | Enthalpy of Stage 15 Extraction Steam | 1,295.66 $Btu/lb_m$ |
| HEXTS16 | Enthalpy of Stage 16 Extraction Steam | 1,247.42 $Btu/lb_m$ |
| HEXTS18 | Enthalpy of Stage 18 Extraction Steam | 1,162.10 $Btu/lb_m$ |
| HEXTS19 | Enthalpy of Stage 19 Extraction Steam | 1,090 $Btu/lb_m$ |
| HCND | Enthalpy of Condenser 1A Hot Well Saturated Water | 95.04 $Btu/lb_m$ |
| HMS | Enthalpy of Main Steam | 1,458.48 $Btu/lb_m$ |
| SMS | Entropy of Main Steam | 1.531348 $Btu/lb_m$ R |
| HHPS | Enthalpy of High-Pressure Turbine Exhaust Steam at Constant Entropy | 1,283.72 $Btu/lb_m$ |
| HHRH | Enthalpy of Hot Reheat Steam | 1,521.65 $Btu/lb_m$ |
| SHRH | Entropy of Hot Reheat Steam | 1.733338 $Btu/lb_m$ R |
| HCXO | Enthalpy of Intermediate Pressure Turbine Exhaust Steam | 1,337.42 $Btu/lb_m$ |
| HIPS | Enthalpy of Intermediate Pressure Turbine Exhaust Steam at Constant Entropy | 1,322.51 $Btu/lb_m$ |
| SCXO | Entropy of Low-Pressure Turbine Bowl Steam | 1.747345 $Btu/lb_m$ R |
| HLPS | Enthalpy of Low-Pressure Turbine Exhaust Steam at Constant Entropy | 1,007.98 $Btu/lb_m$ |
| HCNDPD | Enthalpy of Condensate at Condensate Pump Discharge | 95.61 $Btu/lb_m$ |

| Variable | Description | Test 6 Calculated Value |
|---|---|---|
| HHWA | Enthalpy of HP Condenser 1A Hot Well | 95.04 $Btu/lb_m$ |
| HHWB | Enthalpy of IP Condenser 1B Hot Well | 93.66 $Btu/lb_m$ |
| HHWC | Enthalpy of LP Condenser 1C Hot Well | 77.77 $Btu/lb_m$ |
| HAMB | Enthalpy of Saturated Water | 171.8 $Btu/lb_m$ |
| HAMBCW | Enthalpy of Circulating Water at Ambient Temperature and Pressure | 35.37 $Btu/lb_m$ |
| HDRUM | Boiler Drum Enthalpy | 753.2 $Btu/lb_m$ |

CALCULATION OF CONDENSATE FLOW

$$FCND = C \times K_M \times [(DPCND \times 33.9\ ft\ H_2O \times VCND)/(14.696\ psia \times VSTD)]^{0.5}$$

$$\times \frac{3600\ sec}{1\ h} \times \frac{1}{VCND} \times \frac{ft^3}{lb_m}$$

$$K_M = \frac{A \times (2 \times G)^{0.5} \times F_A}{(1-B^4)^{0.5}}$$

A = Nozzle Throat Area = 0.5283 $ft^2$

G = Local Acceleration of Gravity = 32.138 $ft/sec^2$

$F_A$ = Nozzle Temperature Expansion Factor = 1.0040

B = Ratio of Throat Diameter to Pipe Diameter = 0.4233

$K_M$ = 4.32240

C = Nozzle Discharge Coefficient = 0.9977

FCND = 4,525,831 $lb_m/h$

CALCULATION OF FEEDWATER FLOW FROM NOZZLE PRESSURE DROP

$$FFW = C \times K_M \times [(DPFWN \times 33.9\ ft\ H_2O \times VFW)/(14.696\ psia \times VSTD)]^{0.5}$$

$$\times \frac{3600\ sec}{1\ h} \times \frac{1}{VFW}\ \frac{ft^3}{lb_m}$$

A = 0.3323 $ft^2$

B = 0.4836

$F_A$ = 1.0091

C = 0.9980

FFW = 6,234,122 $lb_m/h$

CALCULATION OF FLUE GAS REHEAT FLOW

$$FFGR = \frac{0.525 \text{ in.}}{ft^{1/2} \text{ sec}} \times D^2 \times C \times F_A \times (DPFGR \times VFGR)^{0.5} \times 3600 \times \frac{1}{VFGR}$$

D = Diameter of Orifice = 7.2037 in.

C = 0.65

$F_A$ = 1.0030

FFGR = 934,100 $lb_m/h$

CALCULATION OF STEAM LEAKAGE NUMBER 4 FLOW

$$FLO4 = 1890.07 \times D^2 \times K \times E \times Y \times [DPLO4/VLO4]^{0.5}$$

D = Orifice Diameter = 3.216 in.

B = 0.799

K = Nozzle Discharge Coefficient = 0.7800

E = Nozzle Expansion Factor = $1 + 2\ (9 \times 10^{-6})\ (TLO4\text{-}70F) = 1.0096$

Y = Expansion Factor for Compressible Flow =

$$1 - (0.41 + 0.35\ B^4)\ \frac{DPLO4}{PLO4 \times (1.3)} = 0.99678$$

FLO4 = 6,345 $lb_m/h$

CALCULATION OF STEAM LEAKAGE NUMBER 6 FLOW

$$FLO6 = 1890.07 \times D^2 \times K \times E \times Y \times [DPLO6/VLO6]^{0.5}$$

D = 2.890 in.

B = 0.7178

K = 0.7130

E = 1.0112

Y = 0.9849

FLO6 = 10,088 $lb_m/h$

CALCULATION OF IP ROTOR COOLING STEAM FLOW

$$FCLGLO = 1890.07 \times D^2 \times K \times E \times Y \times [DPCLGLO/VCLGLO]^{0.5}$$

D = 2.00 in.

B = 0.5227

K = 0.627

E = 1.0135

Y = 0.9874

FCLGLO = 17,755 $lb_m/h$

CALCULATION OF VALVE STEM LEAKOFF FLOW

$$FVSLO = 1890.07 \times D^2 \times K \times E \times Y \times [DPVSLO/VVSLO]^{0.5}$$

D = 1.818 in.

B = 0.7826

K = 0

FVSLO = 0 $lb_m/h$

CALCULATION OF STEAM LEAKOFFS 2, 5, 7, 8, AND 9

$FLO = (PLO/VLO)^{0.5} \times PC$

FLO2 = 935 $lb_m/h$

FLO3 = 37,503 $lb_m/h$

FLO5 = 3,916 $lb_m/h$

FLO7 = 4,634 $lb_m/h$

FLO8 = 2,621 $lb_m/h$

FLO9 = 2,646 $lb_m/h$

CALCULATION OF STEAM SEALS FLOW TO HEATER 1A

FDV1A = $1890.07 \times D^2 \times K \times [DPDV1A/VDV1A]^{0.5}$

D = 12.000 in.

K = 0.76

FDV1A = 3,466 $lb_m/h$

CALCULATION OF STEAM SEALS FLOW TO CONDENSER

FDVCND = $1890.07 \times D^2 \times K \times [DPDVCND/VDVCND]^{0.5}$

D = 10.020 in.

K = 0.76

FDVCND = 0 $lb_m/h$

CALCULATION OF BOILER FEED PUMP TURBINE STEAM FLOW

FSBFPT = $358.93 \times C \times Y \times F_A \times D^2 \times [(DPEXTBFPT \times 406.8 \text{ in. } H_2O)/(14.696 \text{ psia} \times VEXTBFPT)]^{0.5}/(1-B^4)$

D = 7.809 in.

$C_A$ = 0.997

$F_A$ = 1.0105

Y = 0.970

B = 0.45269

FSBFPTA= 124,730 $lb_m/h$

$C_A$ = 0.997

$F_A$ = 1.0105

Y = 0.968

FSBFPTB = 130,361 $lb_m/h$

CALCULATION OF BOILER FEED PUMP SEAL INJECTION FLOWS

$$FBFPI = 0.0438 \times C \times D^2 \times F_A \times (DPBFPI \times 33.9 \text{ ft } H_2O/14.696 \text{ psia})^{0.5} \times 3600 \frac{sec}{h} \times \frac{1}{VCNDPD}$$

$F_A$ = 1.001

$D_1$ = 0.9522 in.

$B_1$ = 0.49106

$C_{1A}$ = 0.620

$C_{1B}$ = 0.620

$C_{1C}$ = 0.619

FBFP1AI = 14,622 $lb_m/h$

FBFP1BI = 8,792 $lb_m/h$

FBFP1CI = 27,724 $lb_m/h$

$D_2$ = 0.92515 in.

$B_2$ = 0.6168

$C_{2A}$ = 0.658

$C_{2B}$ = 0.657

$C_{2C}$ = 0.657

FBFP2AI = 13,083 $lb_m/h$

FBFP2BI = 21,178 $lb_m/h$

FBFP2CI = 20,657 $lb_m/h$

FBFP1RJ = Boiler Feed Pump Rejected Seal Injection Flow = 18,560 $lb_m/h$

FBFP2RJ = Booster Feed Pump Rejected Seal Injection Flow = 47,275 $lb_m/h$

FMSA = Flow of Main Steam Attemperator = 0 $lb_m/h$

FBFPSIR = Boiler Feed Pump Retained Seal Injection Water

= FBFPI - (FBFP1RJ + FBFP2RJ)

= 40,221 $lb_m/h$

CALCULATION OF FEEDWATER HEATER 8 EXTRACTION FLOWS

(Assume half of feedwater flow through each feedwater heater string and no heat loss from heaters)

$$FEXT8A = \frac{FFW\ (HFWO8A - HFWO7A)}{2\ \ (HEXT8A - HDR8A\ )}$$

$$= 0.04651\ FFW$$

$$FEXT8B = \frac{FFW\ (HFWO8B - HFWO7B)}{2\ \ (HEXT8B - HDR8B\ )}$$

$$= 0.04744\ FFW$$

CALCULATION OF FEEDWATER HEATER 7 EXTRACTION FLOWS

$$FEXT7A = \frac{FFW\ (0.5)(HFWO7A - HFWO6A) + FEXT8A\ (HDR7A - HDR8A)}{(HEXT7A - HDR7A\ )}$$

$$= 0.04439\ FFW$$

$$FEXT7B = \frac{FFW\ (0.5)(HFWO7B - HFWO6B\ ) + FEXT8B\ (HDR7B - HDR8B)}{(HEXT7B - HDR7B\ \ )}$$

$$= 0.04410\ FFW$$

CALCULATION OF FEEDWATER HEATER 6 EXTRACTION FLOWS

$$FEXT6A = \frac{FFW\ (0.5)\ (HFWO6A - HFWI6A) + (FEXT7A + FEXT8A)\ (HDR6A - HDR7A)}{(HEXT6A - HDR6A\ )}$$

$$= 0.01892\ FFW$$

$$FEXT6B = \frac{FFW\ (0.5)\ (HFWO6B - HFWI6B) + (FEXT7B + FEXT8B)\ (HDR6B - HDR7B)}{(HEXT6B - HDR6B\ )}$$

$$= 0.01883\ FFW$$

CALCULATION OF DEAERATING HEATER 5 EXTRACTION FLOW

HEAT BALANCE AROUND HEATER 5

FEXT5 = [(FFW - FBFPSIR + FMSA)(HFWO5) - FCND (HCNDI5) -
(FEXT8A + FEXT7A + FEXT6A)(HDR6A) - (FEXT8B + FEXT7B + FEXT6B)
(HDR6B) - FFGR (HFGRR - HFWO5) - FLO4 (HLO4) - FLO6 (HLO6)]/HEXT5

FEXT5 = 0.17941 FFW - 847,297 $lb_m/h$

MASS BALANCE AROUND HEATER 5

FEXT5 = FFW - FBFPSIR + FMSA - FCND - FLO4 - FLO6 - FEXT8A - FEXT7A -
FEXT6A - FEXT8B - FEXT7B - FEXT6B

FEXT5 = 0.77981 FFW - 4,582,485 $lb_m/h$

SOLVING EQUATIONS SIMULTANEOUSLY

FFW = 6,221,229 $lb_m/h$

THUS SOLVING FOR HEATER EXTRACTION FLOWS

FEXT8A = 289,343 $lb_m/h$

FEXT8B = 295,131 $lb_m/h$

FEXT7A = 276,190 $lb_m/h$

FEXT7B = 274,386 $lb_m/h$

FEXT6A = 117,692 $lb_m/h$

FEXT6B = 117,133 $lb_m/h$

FEXT5 = 268,869 $lb_m/h$

CALCULATION OF FEEDWATER HEATER 4 EXTRACTION FLOW

$$\text{FEXT4} = \frac{\text{FCND (HCNDO4 - HCNDI4)}}{\text{(HEXT4 - HDR4)}}$$

FEXT4 = 142,165 $lb_m/h$

CALCULATION OF FEEDWATER HEATER 3 EXTRACTION FLOW

$$FEXT3 = \frac{FCND\ (HCNDO3 - HCNDI3) + FEXT4\ (HDR3 - HDR4)}{(HEXT3 - HDR3)}$$

$$FEXT3 = 279{,}883\ lb_m/h$$

CALCULATION OF FEEDWATER HEATER 2 EXTRACTION FLOW

$$FEXT2 = \frac{FCND\ (HCNDO2 - HCNDI2) + (FEXT3 + FEXT4)(HDR2 - HDR3)}{(HEXT2 - HDR2)}$$

$$FEXT2 = 142{,}806\ lb_m/h$$

CALCULATION OF FEEDWATER HEATER 1 EXTRACTION FLOW

$$FEXT1A = \frac{FCND\ (0.3333)(HCNDO1A - HCNDI1) + FDV1A\ (HDR1 - HDV1A)}{(HEXT1A - HDR1)}$$

$$FEXT1A = 38{,}629\ lb_m/h$$

$$FEXT1B = \frac{FCND\ (HCNDO1B - HCNDI1)}{3\ (HEXT1B - HDR1)}$$

$$FEXT1B = 41{,}836\ lb_m/h$$

$$FEXT1C = \frac{FCND\ (HCNDO1C - HCNDI1)}{3\ (HEXT1C - HDR1)}$$

$$FEXT1C = 42{,}825\ lb_m/h$$

Generator output is calculated with the equations provided in the Appendix.

Test turbine stage flows and condenser flows are then calculated by performing a mass balance around the turbine.

The used energy end point of the turbine is calculated by performing a heat balance around the turbine using the measured generator output and measured condenser flow.

The expansion line end point (ELEP) of the turbine is then iterated by assuming a steam quality at the test exhaust pressure and calculating the ELEP. This is done until the ELEP between successive iterations varies less than 0.1 Btu/$lb_m$.

The turbine stage efficiencies are then calculated as follows.

HPEFF = High-Pressure Efficiency $= \frac{(HMS - HCRH)}{(HMS - HHPS)}$ x 100 percent = 88.33 percent

IPEFF = Intermediate Pressure Efficiency $= \frac{(HHRH - HCXO)}{(HHRH - HIPS)}$ x 100 percent

= 92.51 percent

LPEFFE = Low-Pressure Expansion Line End Point Efficiency

$= \frac{(HCXO - ELEP)}{(HCXO - HLPS)}$ x 100 percent = 93.06 percent

LPEFFU = Low-Pressure Used Energy End Point Efficiency

$= \frac{(HCXO - UEEP)}{(HCXO - HLPS)}$ x 100 percent = 90.63 percent

GROUP 1 CORRECTIONS

To accurately compare the test results from each load against the guarantee heat rate, it is necessary to correct the cycle from actual test conditions to specified conditions.

This is accomplished by calculating the test main steam flow and then assuming the following specified conditions.

(1) No main or reheat steam attemperation.
(2) No change in water level in the system or makeup.
(3) No boiler feed pump seal injection.
(4) Specified terminal difference and subcooler approach temperatures in the feedwater heaters.
(5) Specified enthalpy rise across the condensate, boiler, and booster boiler feed pumps.
(6) No subcooling of condensate leaving the condenser.
(7) Specified pressure drops in feedwater heater extraction lines.
(8) Seventy-five percent engine efficiency of boiler feed pump-boiler feed pump turbines.
(9) No heat loss from extraction lines.
(10) Specified flue gas reheat heat loss from deaerator.

Test flow/stage pressure ratios are calculated after each stage in the turbine with test temperatures and stage pressures. Then, new extraction flows are calculated using specified extraction line pressure drops, feedwater heater temperature differences, and all other specified conditions as stated previously.

New boiler feed pump turbine steam flows were calculated from the General Electric design heat balances and using 75 percent engine efficiency since the boiler feed pump turbines were not tested.

| Test Relationship | W-$lb_m$/h | P-psia | W/P |
|---|---|---|---|
| Throttle Flow | 6,221,229 | | |
| Valve Stem Leakoff | -935 | | |
| IP Cooling Leakoff | -17,755 | | |
| No. 3 Gland Leakoff | -37,503 | | |
| No. 8 Extraction Flow | -584,474 | | |
| Steam Flow Following Extraction | 5,580,562 | 1,075.375 | 5,189.41 |
| No. 4 Gland Leakoff | -6,345 | | |
| No. 5 Gland Leakoff | -3,916 | | |
| No. 6 Gland Leakoff | -10,088 | | |
| No. 7 Gland Leakoff | -4,634 | | |
| No. 7 Extraction Flow | -550,575 | | |
| No. 3 Gland Leakoff | +37,503 | | |
| Reheat Steam Flow | 5,042,507 | | |
| Valve Stem Leakoff | +0 | | |
| IP Cooling Leakoff | +17,755 | | |
| Steam Flow at IP Turbine | 5,060,262 | 521.025 | 9,712.13 |
| No. 6 Extraction Flow | -234,825 | | |
| Steam Flow Following Extraction | 4,825,437 | 231.645 | 20,831.17 |
| No. 5 Extraction Flow | -268,869 | | |
| BFPT Extraction Flow | -255,092 | | |
| No. 8 Gland Leakoff | -2,621 | | |
| No. 9 Gland Leakoff | -2,646 | | |
| Crossover Steam Flow | 4,296,209 | 121.608 | 35,328.3 |
| No. 4 Extraction Flow | -142,165 | | |

| Test Relationship | W-lb$_m$/h | P-psia | W/P |
|---|---|---|---|
| Steam Flow Following Extraction | 4,154,044 | 64.575 | 64,329 |
| No. 3 Extraction Flow | -279,883 | | |
| Steam Flow Following Extraction | 3,874,161 | 39.325 | 98,516 |
| No. 2 Extraction Flow | -142,805 | | |
| Steam Flow Following Extraction | 3,731,356 | 11.519 | 323,931 |
| No. 1 Extraction Flow | -123,290 | | |
| Steam Flow to Condenser | 3,608,066 | 4.943 | 729,934 |

With the high-pressure turbine exhaust pressure kept constant, new stage flows are calculated for the turbine and the flow at each stage is divided by the test flow/stage pressure ratio to find new extraction pressures. If these new extraction pressures vary by more than 1 percent from the previous extraction pressures, stage flows and stage extraction pressures are iterated until the difference in extraction pressures on all heaters between two successive iterations is less than 1 percent.

| | Flow, lb$_m$/h | |
|---|---|---|
| Iterated Stage Flows | First Iteration | Second Iteration |
| Throttle Flow | 6,221,229 | 6,221,229 |
| Valve Stem Leakoff | 935 | 935 |
| IP Cooling Leakoff | 17,755 | 17,755 |
| No. 3 Gland Leakoff | 37,503 | 37,503 |
| No. 8 Extraction Flow | 589,765 | 588,760 |
| Steam Flow Following Extraction | 5,575,271 | 5,576,276 |
| No. 4 Gland Leakoff | 6,345 | 6,345 |
| No. 5 Gland Leakoff | 3,916 | 3,916 |
| No. 6 Gland Leakoff | 10,088 | 10,088 |
| No. 7 Gland Leakoff | 4,634 | 4,634 |
| No. 7 Extraction Flow | 563,230 | 564,540 |
| No. 3 Leakoff Flow | 37,503 | 37,503 |

| Iterated Stage Flows | Flow, $lb_m$/h First Iteration | Second Iteration |
|---|---|---|
| Reheat Steam Flow | 5,024,561 | 5,024,256 |
| Valve Stem Leakoff | 0 | 0 |
| IP Cooling Leakoff | 17,755 | 17,755 |
| Steam Flow at IP Turbine | 5,042,316 | 5,042,011 |
| No. 6 Extraction Flow | 229,485 | 231,590 |
| | | |
| Steam Flow Following Extraction | 4,812,831 | 4,810,421 |
| No. 5 Extraction Flow | 255,560 | 255,035 |
| BFPT Extraction Flow | 294,815 | 294,815 |
| No. 8 Gland Leakoff | 2,621 | 2,621 |
| No. 9 Gland Leakoff | 2,646 | 2,646 |
| | | |
| Crossover Steam Flow | 4,257,189 | 4,255,304 |
| No. 4 Extraction Flow | 139,680 | 139,360 |
| | | |
| Steam Flow Following Extraction | 4,117,509 | 4,115,944 |
| No. 3 Extraction Flow | 278,500 | 278,515 |
| | | |
| Steam Flow Following Extraction | 3,839,009 | 3,837,429 |
| No. 2 Extraction Flow | 156,270 | 155,395 |
| | | |
| Steam Flow Following Extraction | 3,682,739 | 3,682,034 |
| No. 1 Extraction Flow | 112,660 | 110,795 |
| | | |
| Steam Flow to Condenser | 3,570,079 | 3,571,239 |

| Iterated Stage Pressures, psia | Test | First Iteration | Second Iteration |
|---|---|---|---|
| Stage 4 | 1075.375 | 1,074.356 | 1,074.549 |
| Hot Reheat | 521.025 | 519.177 | 519.146 |
| Stage 11 | 231.645 | 231.040 | 230.924 |
| Stage 14 | 121.608 | 120.504 | 120.450 |
| Stage 15 | 64.575 | 64.007 | 63.983 |
| Stage 16 | 39.325 | 38.968 | 38.952 |
| Stage 18 | 11.519 | 11.369 | 11.367 |
| Stage 19 | 4.943 | 4.891 | 4.893 |

A new corrected generator load is calculated by performing a heat balance around the turbine using the new turbine flows. Electrical and mechanical losses in the generator are subtracted to find the corrected generator load.

The heat rate is then calculated using the new reheat flow and hot reheat enthalpy, condensate flow, and the specified enthalpy rise across the condensate and booster boiler feed pumps.

$$\text{Heat Rate} = \frac{\text{QINPUT}}{\text{QGEN}}$$

QGEN = Corrected Generator Load

QINPUT = FMS (HMS-HFW08) + FFW (DHBBFP) + FCND (DHCNDP)
+ FRHS (HHRH - HCRH) + 0.001 FFW (HDRUM - HFW08)

DHCNDP = Specified Enthalpy Rise Across Condensate Pump

DHBBFP = Specified Enthalpy Rise Across Booster Boiler Feed Pump

Test 6 Group I Corrected Heat Rate

= [6,221,229 (1,458.48 - 548.25) + 6,283,440 (1.45) +
4,627,080 (1.48) + 5,024,256 (1,521.95 - 1,304.12)]/854,450.2

= 7,928.4 Btu/kWh

Group II corrections are then applied to the heat rate and load for nonspecified turbine steam conditions as follows.

| | Heat Rate | Load |
|---|---|---|
| Initial Throttle Pressure | 1.0005 | 0.9920 |
| Initial Throttle Temperature | 1.0008 | 1.0005 |
| Reheater Pressure Drop | 0.9977 | 1.0060 |
| Exhaust Pressure | 1.02134 | 0.9791 |
| Hot Reheat Steam Temperature | 0.9996 | 1.0015 |

$$\text{Corrected Heat Rate} = \frac{\text{Corrected Heat Rate (Group I)}}{\text{Total Group II Heat Rate Corrections}}$$

$$\text{Corrected Load} = \frac{\text{Corrected Load (Group I)}}{\text{Total Group II Load Corrections}}$$

Total Group II Heat Rate Corrections = 1.01991

Total Group II Load Corrections = 0.9790

Corrected Heat Rate = 7773.6 Btu/kWh

Corrected Load = 872,779 kW

CALCULATION OF FEEDWATER HEATER PERFORMANCE

TD = Terminal Temperature Difference

= TSAT - TFWI

TSAT = Saturation Temperature of Extraction Steam at Test Pressure

TFWO = Temperature of Feedwater out of Heater

SA = Subcooler Approach Temperature

= TDR - TFWI

TDR = Feedwater Heater Drain Temperature

TFWI = Temperature of Feedwater into Heater

TD8A = 0.42 F

SA8A = 7.18 F

TD8B = -0.74 F

SA8B = 7.22 F

TD7A = -0.98 F

SA7A = 9.25 F

TD7B = -0.15 F

SA7B = 8.26 F

TD6A = -1.33 F

SA6A = 7.51 F

TD6B = -1.22 F

SA6B = 8.03 F

TD5 = -0.14 F

TD4 = -0.28 F

SA4 = 4.79 F

TD3 = -0.01 F

SA3 = 8.74 F

TD2 = 2.13 F

SA2 = 7.90 F

TD1A = 0.29 F

TD1B = 0.25 F

TD1C = 5.35 F

SA1 = 5.45 F

CALCULATION OF BOILER FEED PUMP PERFORMANCE

FFWBFPA = Flow Feedwater Boiler Feed Pump A (Station Data) = 2,970,960 $lb_m/h$

DH = Developed Head

VF = Volumetric Flow

CVF = Corrected Volumetric Flow

CDH = Corrected Developed Head

EDH = Expected Developed Head

RP = Relative Performance

SG = Specific Gravity of Water Pumped

EFFBFPA = Boiler Feed Pump A Efficiency

EFFBFPA = VF x DH x SG x 100 x 8.33/(33,000 x HPBFPTA)

VFWPA = Average Specific Volume Water Pumped

DH = [(VFWPDA x PFWPD) - (VFWPIA x PFWPI)] x 144 $in.^2/ft^2$

DH = 6,624.2 ft

VF = FFWBFPA x VFWPA x 7.4805/60

VF = 6,584.6 gpm

CVF = VF x 5,700 rpm/SPBFPTA

CVF = 7,153.6 gpm

CDH = DH x $(5750)^2/SPBFPTA^2$

CDH = 7,818.5 ft

EDH = f(CVF)

= 8,562.8 ft

RP = DH/EDH

RP = 0.774

SG = 0.01605/VFWPA

SG = 0.90286

EFFBFPA = 80.51 percent

CONDENSER PERFORMANCE

FSCND = Flow of Steam to Condenser = 3,608,066 $lb_m/h$

TSATA = Temperature of Saturated Water in HP Condenser A = 127.06 F

TSATB = Temperature of Saturated Water in IP Condenser B = 125.67 F

TSATC = Temperature of Saturated Water in LP Condenser C = 109.75 F

Correction Factors for Off-Design Circulating Water

Inlet Temperature - (Refer to Standards of the Heat Exchange Institute in Section 6.0)

HTCFA = Heat Transfer Coefficient Correction for HP Condenser A = 1.101

HTCFB = Heat Transfer Coefficient Correction for IP Condenser B = 1.065

HTCFC = Heat Transfer Coefficient Correction for LP Condenser C = 1.065

Log Mean Temperature Difference

TLMDC = (TCWO - TCWI)/Ln[(TSAT - TCWI)/(TSAT - TCWO)]

TLMDCA = 16.36 F

TLMDCB = 20.90 F

TLMDCC = 15.22 F

Terminal Temperature Difference

TTD = TSAT - TCWO

TTDA = 9.16 F

TTDB = 9.45 F

TTDC = 9.30 F

FCNDC = Flow to Condenser C = FSCND/3 + FSBFPTB + FEXT4 + FEXT3 + FEXT2 + FEXT1A + FEXT1B + FEXT1C + FDV1A

FCNDC = 2,024,660 $lb_m$/h

FCNDB = Flow to Condenser B = FSCND/3 + FCNDC

FCNDB = 3,227,349 $lb_m$/h

FCNDA = Flow to Condenser A = FSCND/3 + FCNDB + FSBFPTA + FDVCND

FCNDA = 4,558,968 $lb_m$/h

Individual Used Energy End Point of Each Condenser

UEEPA = 1,047.71 Btu/$lb_m$

UEEPB = 1,045.29 Btu/$lb_m$

UEEPC = 1,024.87 Btu/$lb_m$

QCND = Heat Transferred to Circulating Water in Condenser

QCNDA = 1,269,487,071 Btu/h

QCNDB = 1,112,344,039 Btu/h

QCNDC = 1,285,791,473 Btu/h

Calculated Heat Transfer Coefficient

UC = QCND/(Area of Condenser x TLMDC)

AREA = 150,000 $ft^2$

UCA = 517.31 Btu/h - $ft^2$ - F

UCB = 354.81 Btu/h - $ft^2$ - F

UCC = 563.20 Btu/h - $ft^2$ - F

Corrected Heat Transfer Coefficient

UCXC = UX x TCFCW

UCAC = 569.56 Btu/h - $ft^2$ - F

UCBC = 377.88 Btu/h - $ft^2$ - F

UCCC = 599.81 Btu/h - $ft^2$ - F

Cleanliness Factor

CFC = 100 x UCXC/UDCX

UDCX = Minimum Cleanliness Heat Transfer Coefficient

CFCA = 569.56 x 100/603.13 = 94.43 percent

CFCB = 377.88 x 100/604.26 = 62.54 percent

CFCC = 599.81 x 100/604.26 = 99.26 percent

# 6.0 REFERENCES

"Fluid Meters"; American Society of Mechanical Engineers - Sixth Edition, New York, 1971.

"Flow of Fluids"; Crane Engineering Division, Technical Paper No. 410, New York, 1985.

"ASME Steam Tables"; American Society of Mechanical Engineers - Fourth Edition, New York, 1979.

"Steam Turbines, PTC 6.0"; American Society of Mechanical Engineers, New York, 1976.

"Steam Turbines, PTC 6.0, Appendix A"; American Society of Mechanical Engineers, New York, 1982.

"Steam Turbines, PTC 6.1, Alternative Test"; American Society of Mechanical Engineers, New York, 1984.

"Performance Test Report, Unit 1, Volume 1, Turbine Cycle", Black & Veatch, Kansas City, 1987.

# E L E C T R I C A L   L O A D   C A L C U L A T I O N

1) SECONDARY WATTS = ( COUNTS * 0.3 )/( TIME(hr) * 6.0 )

2) CORR'D VOLTS = READING * 120./CFVOLTS

A PHASE ; CFVOLTS = 119.80
B PHASE ; CFVOLTS = 119.94
C PHASE ; CFVOLTS = 119.77

3) CORR'D AMPS = READING * 0.1/CFAMPS

A PHASE ; CFAMPS = .09982
B PHASE ; CFAMPS = .09991
C PHASE ; CFAMPS = .09996

4) POWER FACTOR (PF) = [1]/([2]*[3])

5) WATTHOUR METER CALIBRATION FOR TEST VALUE OF [CORR'D AMPS] AND [POWER FACTOR] AND [CORR'D VOLTS]

6) CORR'D POWER FACTOR = [4] * [5]

7) CORR'D SECONDARY WATTS = [1] * [5]

8) PT RATIO = 115.0

9) PT CALIBRATION = 0.9986 A PHASE
0.9986 B PHASE
0.9983 C PHASE

10) CT RATIO = 5000

11) CT CALIBRATION = 1.0000 A PHASE
1.0000 B PHASE
1.0000 C PHASE

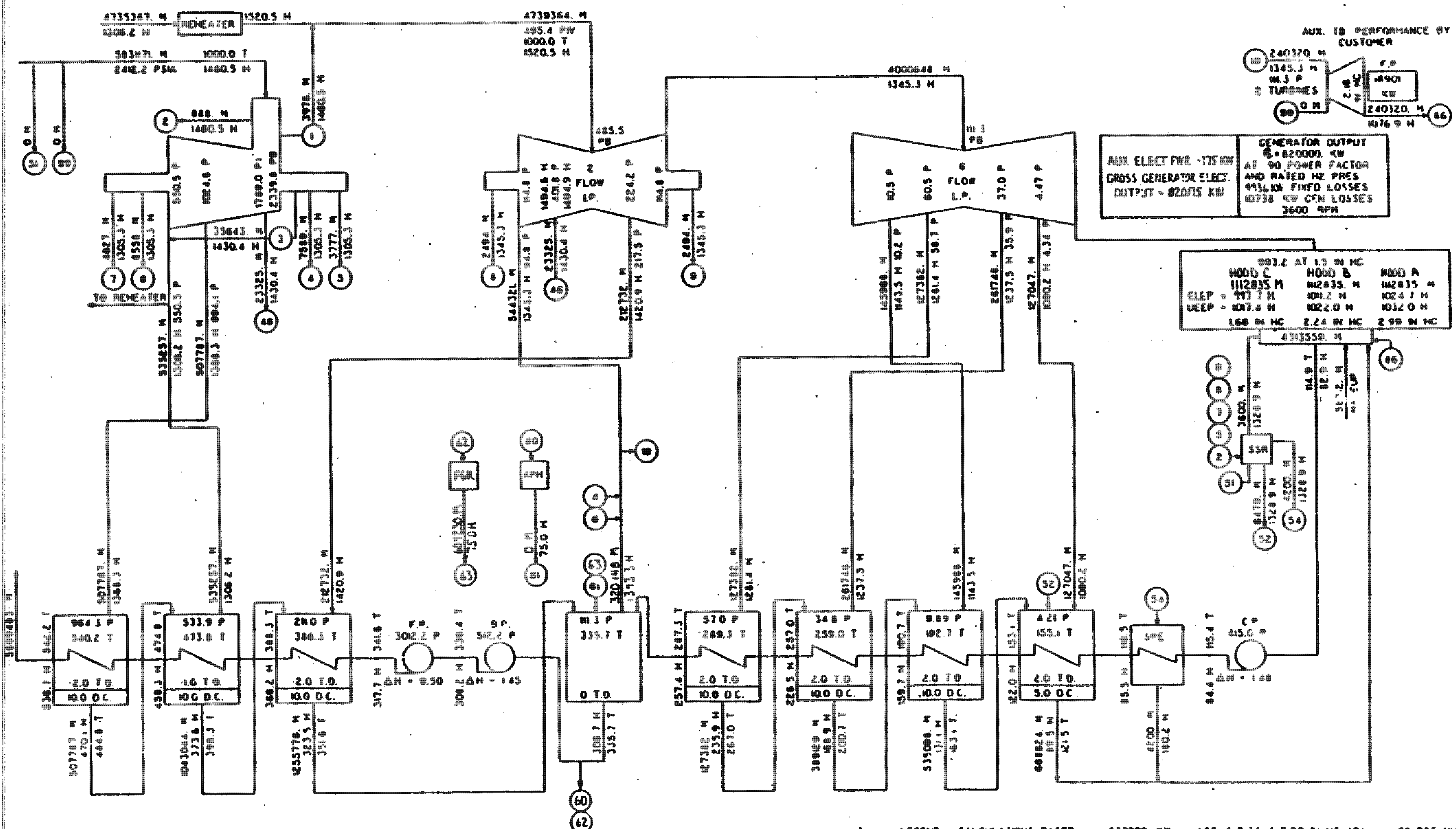
12) KW = [7] * [8] * [9] * [10] * [11] /1000.

13) TOTAL KW = KW (A PHASE) + KW (B PHASE) + KW (C PHASE)

14) AVG. (PF) = [PF (A PHASE) + PF (B PHASE) + PF (C PHASE)]/3

481 HB III

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY




CUSTOMER DEFINED VALVE BEST POINT NET HEAT RATE = $\frac{5831171.M(1460.5H-536.7H)+4735387.M(1520.5H-1306.2H)+4313559.M(1.48H)+5831.M(720.5H-536.7H)}{820000\ KW}$ = 7816 $\frac{Btu}{Kw\text{-}Hr}$

LEGEND CALCULATIONS BASED ON 1967 ASME STEAM TABLES
M - FLOW LB/HR
P - PRESSURE-PSIA
H - ENTHALPY BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66 / 2.24 / 2.90 IN HG ABS 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000 / 1000 F
GEN 991000 KVA .90 PF LIQ

Klw Koran

03141 1 DB0281 9523 L 5
481 HB III 6 24 81

GENERAL ELECTRIC COMPANY, SCHENECTADY N.Y.

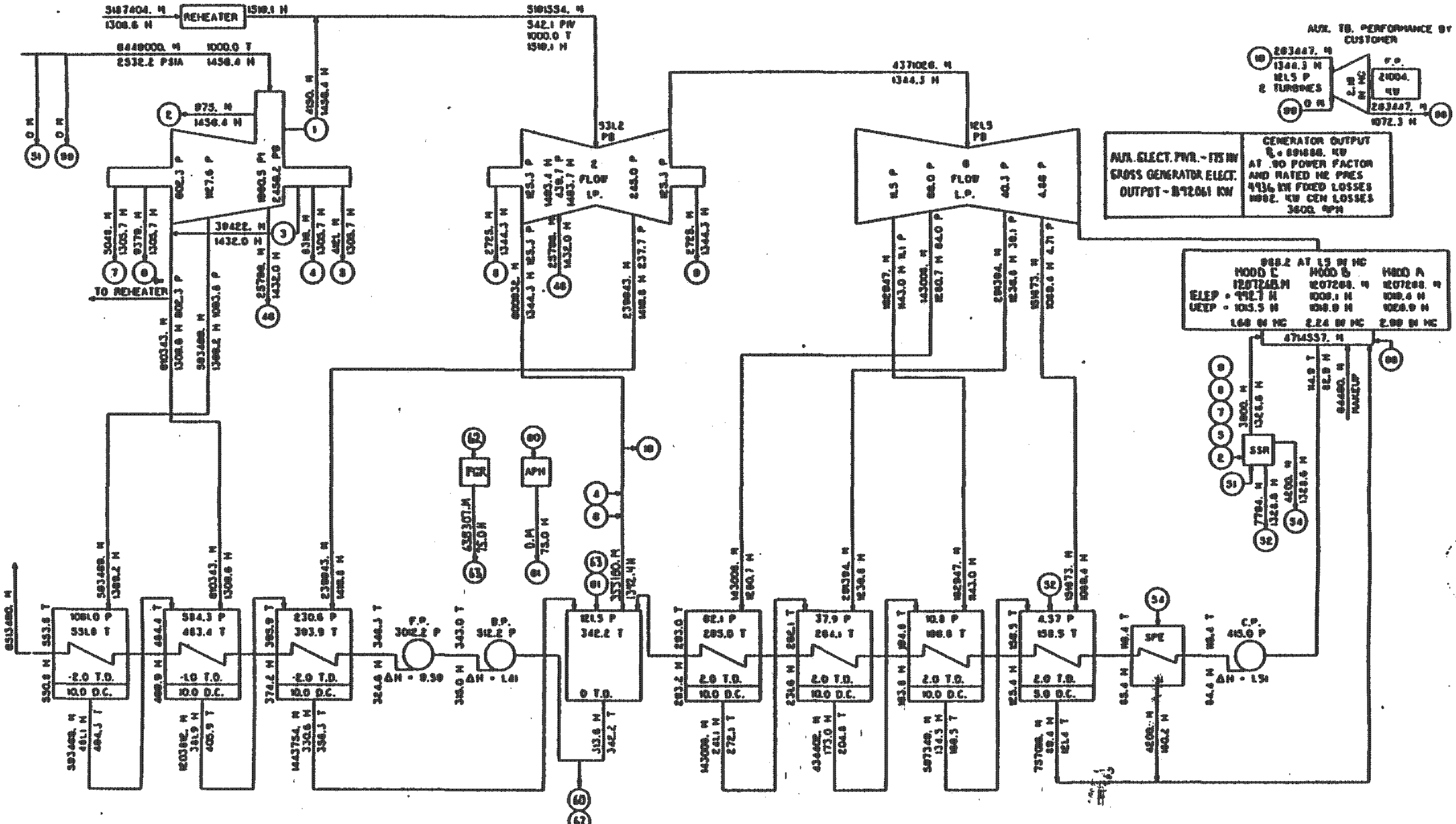
IP14_007449

481 HB 112

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY

CALCULATED DATA - NOT GUARANTEED

RATING FLOW IS 5931171. H AT INLET STEAM CONDITIONS OF 2412.2 PSIA AND 1000.0 T TO ASSURE THAT THE TURBINE WILL PASS THIS FLOW, CONSIDERING VARIATIONS IN FLOW COEFFICIENTS FROM EXPECTED VALUES, SHOP TOLERANCES ON DRAWING AREAS, ETC. WHICH MAY AFFECT THE FLOW, THE TURBINE IS BEING DESIGNED FOR A DESIGN FLOW (RATING FLOW PLUS 3.0 PERCENT) OF 6122730. H
THE EQUIVALENT DESIGN FLOW AT 2332.2 PSIA AND 1000.0 T IS 6449000. H .




CUSTOMER DEFINED
VALVE BEST POINT = $\frac{6449000.H(1456.4H-550.8H)+5187404.H(1519.1H-1306.6H)+4714557.H(1.51H)+6449.H(720.5H-550.8H)}{891886\ KW}$ = 7793 $\frac{Btu}{Kw\text{-}Hr}$
NET HEAT RATE

LEGEND CALCULATIONS BASED ON 1967 ASME STEAM TABLES
H - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000. KW 1.68 / 2.24 / 2.90 IN HG ABS. 1.00 PCT MU
TCOF 30.0 IN. LSB 3600 RPM
2400 PSIG 1000. / 1000. T
GEN- 990000. KVA .90 PF LIB

KW Koran

03ICT 1 080E01 0 0 12

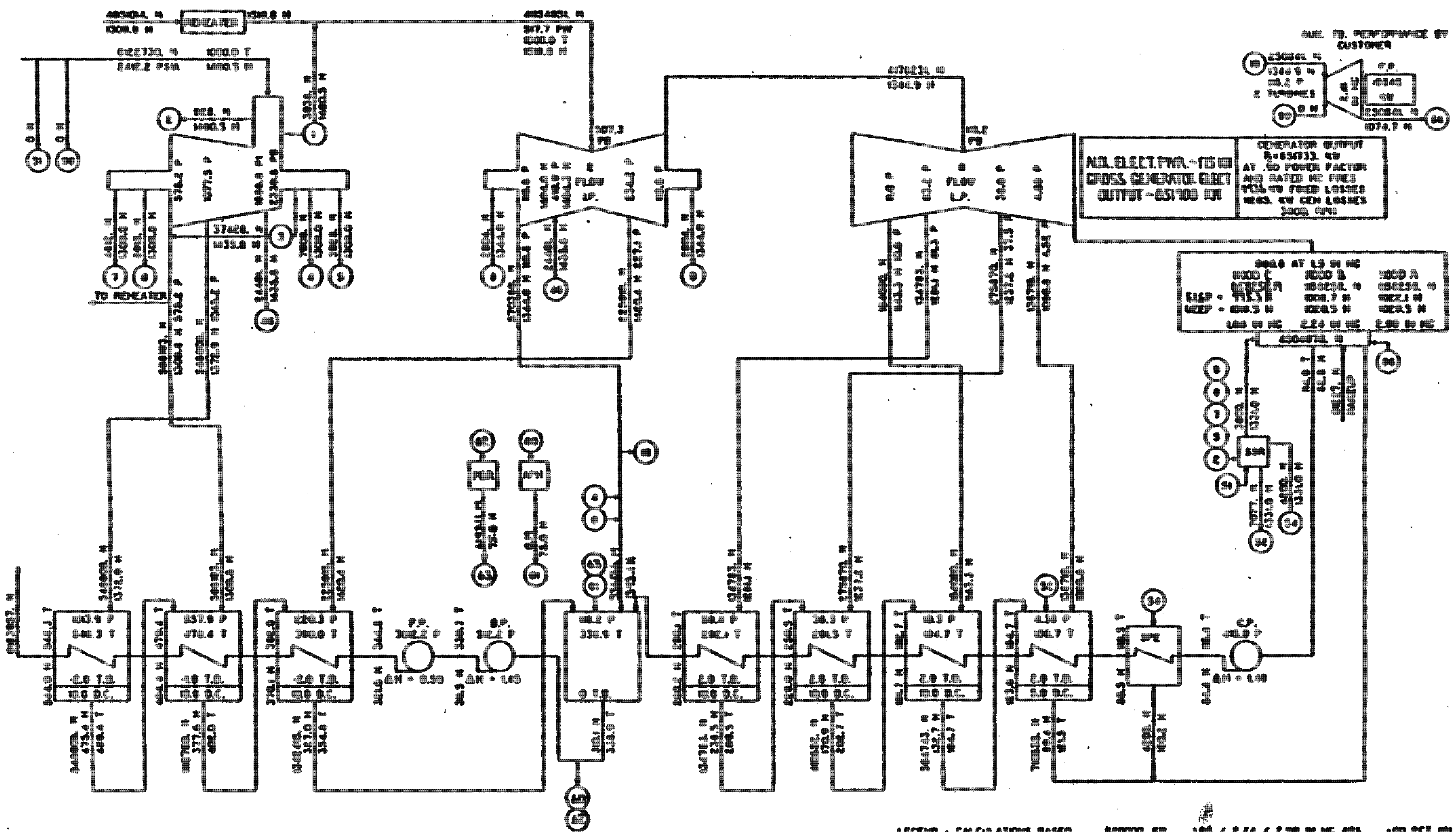
IP14_007450

81 HB 143

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY

CALCULATED DATA - NOT GUARANTEED

RATING FLOW IS 583[illegible] H AT INLET STEAM CONDITIONS OF 2412.2 PSIA AND 1000.0 T
TO ASSURE THAT THE TURBINE WILL PASS THIS FLOW, CONSIDERING VARIATIONS IN FLOW COEFFICIENTS
FROM EXPECTED VALUES, SHOP TOLERANCES ON OPENING AREAS, ETC WHICH MAY AFFECT THE FLOW, THE
TURBINE IS BEING DESIGNED FOR A DESIGN FLOW RATING FLOW PLUS 5.0 PERCENT OF 6122730. H




CUSTOMER DEFINED
VALVE BEST POINT = 6122730.M(1460.5H-544.0H)+4951016.M(1519.0H-1309.0H)+4534976.M(1.40H)+6123.M(720.5H-544.0H) / 851733 KW = 7818 BTU/KW-HR
NET HEAT RATE

LEGEND - CALCULATIONS BASED
ON 1967 ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000. KW 1.86 / 2.24 / 2.90 IN HG ABS. 100 PCT MU
TC6F 30.0 IN LSB 3600 RPM
2400 PSIG 1000 / 1000 F
GEN- 980000. KVA 90 PF LID

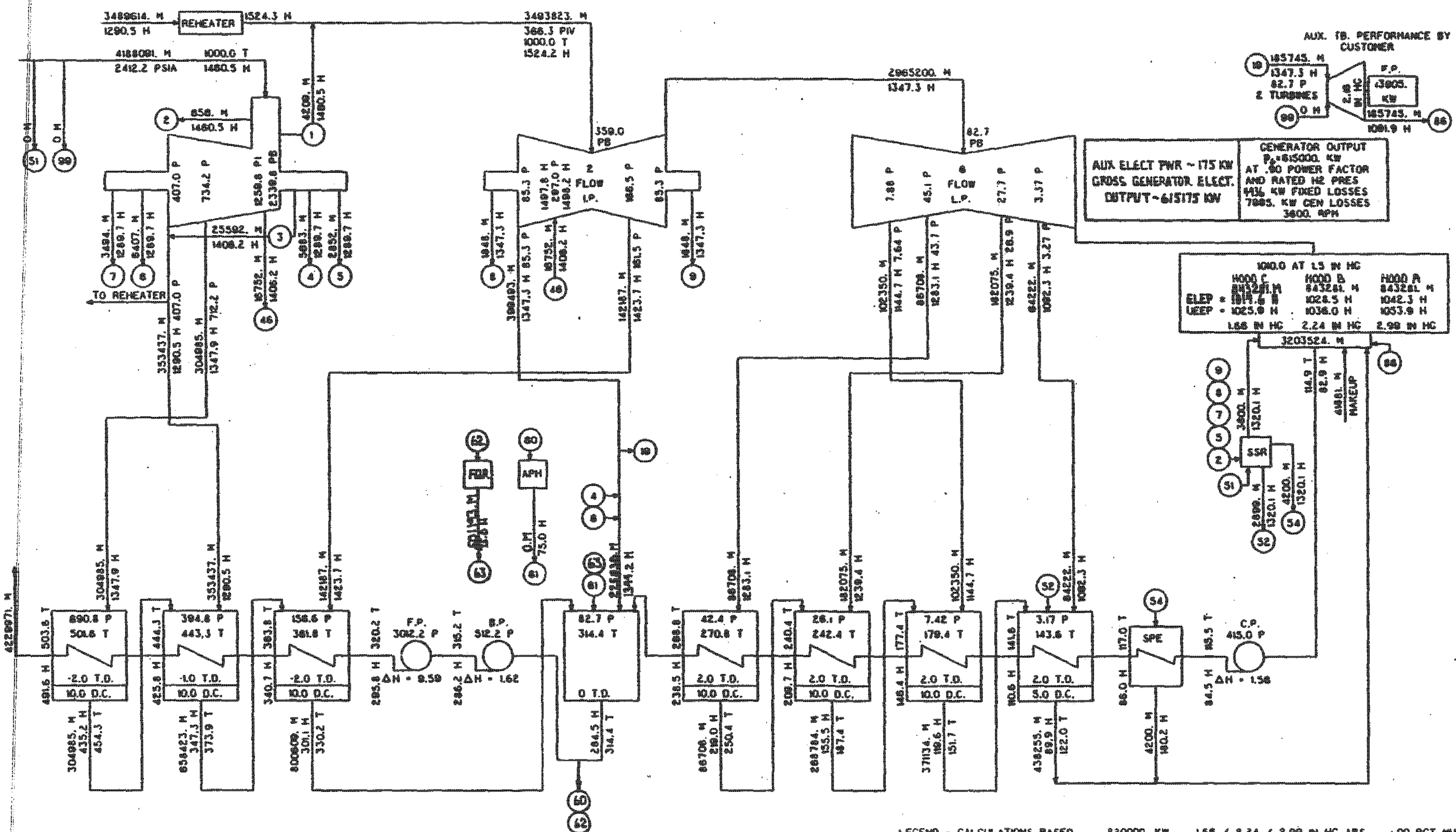
KW Koran

334AT I DBOE19 0 6 0 7-17-80
481 HB 143

GENERAL ELECTRIC COMPANY, SCHENECTADY N.Y.

IP14_0074S1

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY




CUSTOMER DEFINED
VALVE BEST POINT = $\frac{4188091.M(1460.5H-491.6H)+3489614.M(1524.3H-1290.5H)+3203524.M(1.56H)+4188.M(720.5H-491.6H)}{615000 \text{ KW}}$ = 7934 $\frac{BTU}{KW/HR}$
NET HEAT RATE

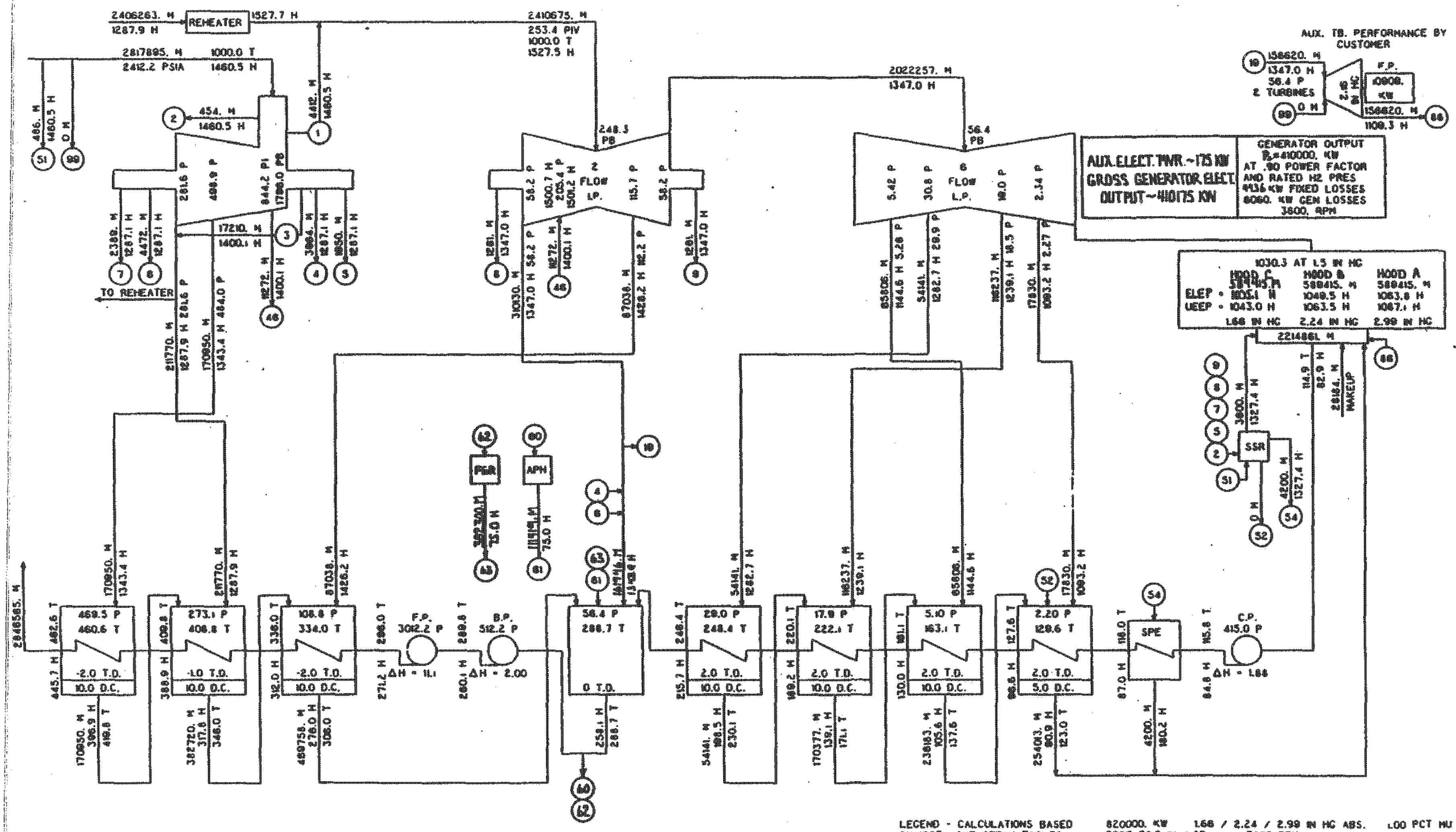
LEGEND - CALCULATIONS BASED ON 1967 ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000. KW 1.66 / 2.24 / 2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000. / 1000. T
GEN- 991000. KVA .90 PF 1.10

KW Keon

534AT I 080291 6840 0 13
481 HB 146 7-17-81

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY




CUSTOMER DEFINED VALVE BEST POINT NET HEAT RATE $= \frac{2817895.M(1460.5H-445.7H)+2406263.M(1527.7H-1287.9H)+2214861.M(1.88H)+2818.M(720.5H-445.7H)}{410000 \text{ KW}} = 8394 \frac{\text{BTU}}{\text{KW/HR}}$

LEGEND - CALCULATIONS BASED ON 1967 ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000. KW 1.66 / 2.24 / 2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000. / 1000. T
GEN- 981000. KVA .90 PF LIQ

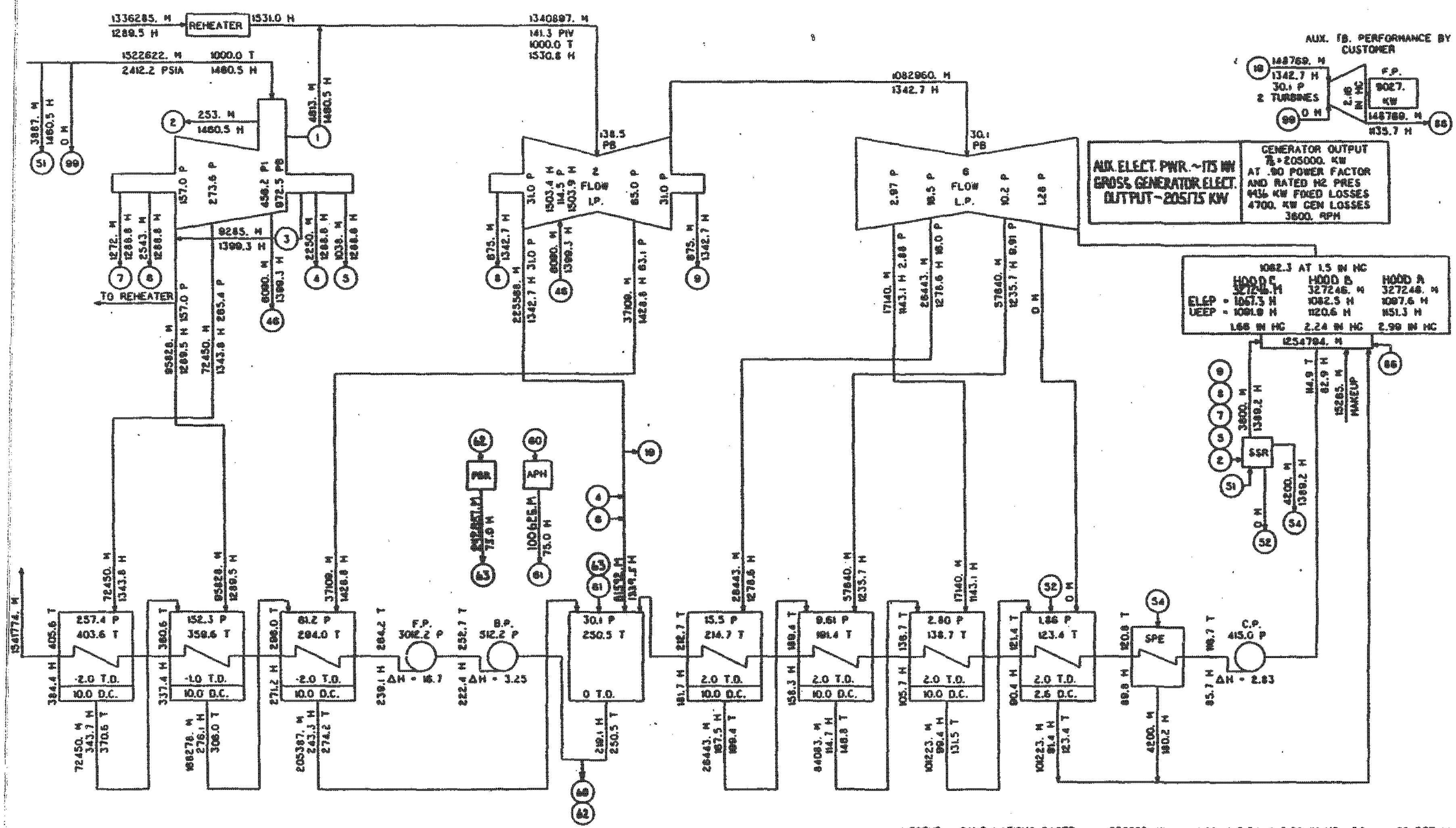
Kw Kozan

GENERAL ELECTRIC COMPANY. SCHENECTADY N.Y.

534AT 1 080281 4602 0 14
481 HB 147 7-17-81

IP14_007453

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY




CUSTOMER DEFINED
VALVE BEST POINT = $\frac{1522622.M(1460.5H-384.4H)+1336285.M(1531.0H-1289.5H)+1254794.M(2.83H)+1523.M(720.5H-384.4H)}{205000\ KW}$ = 9587 $\frac{BTU}{KW/HR}$
NET HEAT RATE

LEGEND - CALCULATIONS BASED
ON 1967 ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000. KW 1.66 / 2.24 / 2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000. / 1000. T
GEN- 991000. KVA .90 PF LIQ

KW Kora

534AT 1 DB0291 2486 0 15
481 HB 148 7-17-81

GENERAL ELECTRIC COMPANY, SCHENECTADY N.Y.

452 HB 890

# NET HEAT RATE CURVE

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.0 PCT MU
TC6F 30.0 IN LSB 3600 RPM
2400 PSIG 1000./1000. T

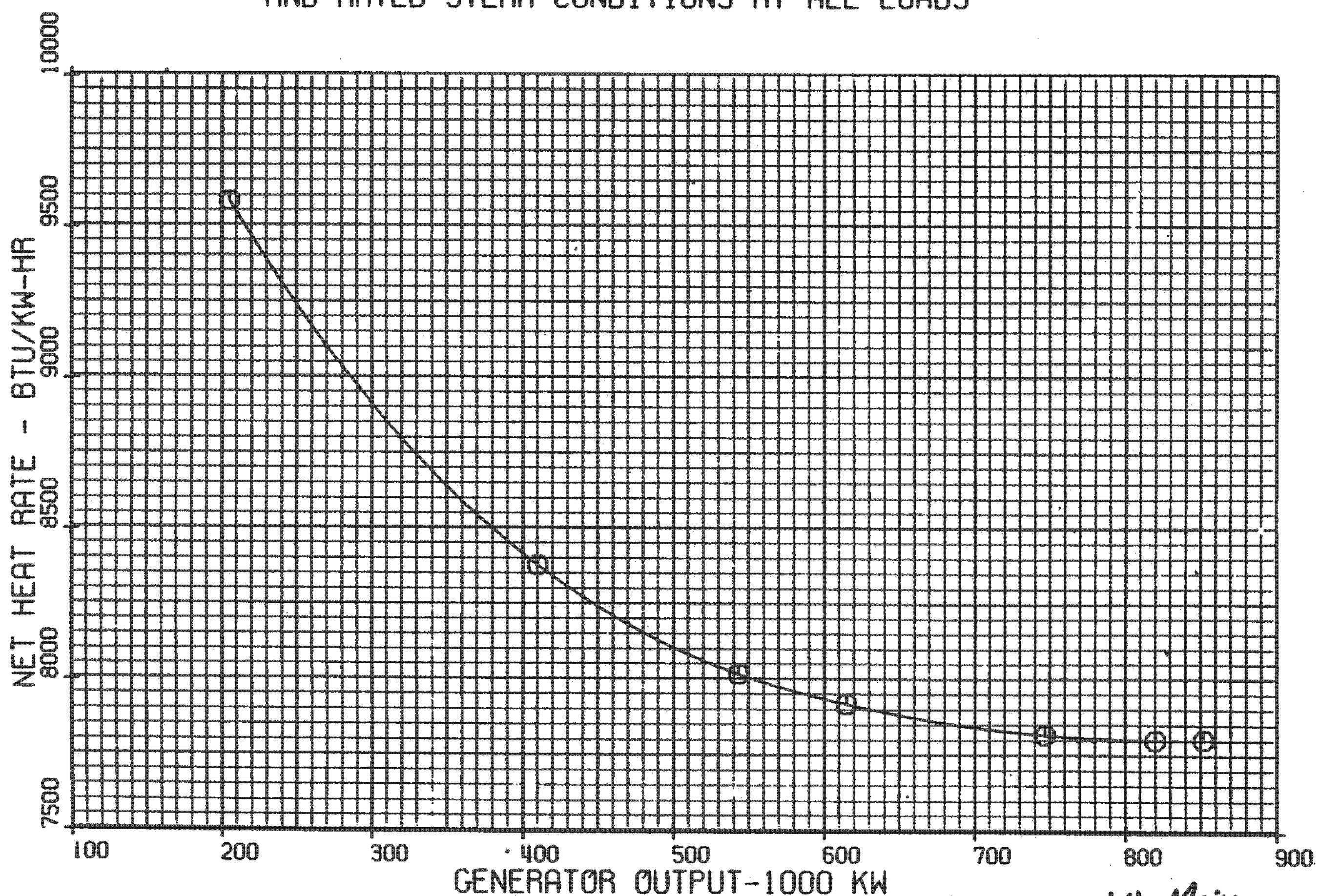
THESE HEAT RATES ARE BASED ON NORMAL EXTRACTION OPERATION AS SHOWN ON HEAT BALANCE 481 HB 111

DASHED PORTION OF CURVE IS AT FLOWS IN EXCESS OF RATING FLOW

CIRCLED POINTS REPRESENT POINTS THROUGH WHICH CURVE WAS DRAWN

THIS CURVE IS NOT GUARANTEED

THESE HEAT RATES ARE AT 1.66,2.24,2.99 IN.HG.ABS.EXH. PRESS.,1 PCT MU AND RATED STEAM CONDITIONS AT ALL LOADS




K.K. Majoy

GENERAL ELECTRIC COMPANY, SCHENECTADY, NEW YORK 11/30/81 452 HB 890

IP14_007455

452 HB 891

# GENERATOR LOSSES

991000 KVA AT 63 PSIG H2 PRESS
CONDUCTOR COOLED 3600 RPM

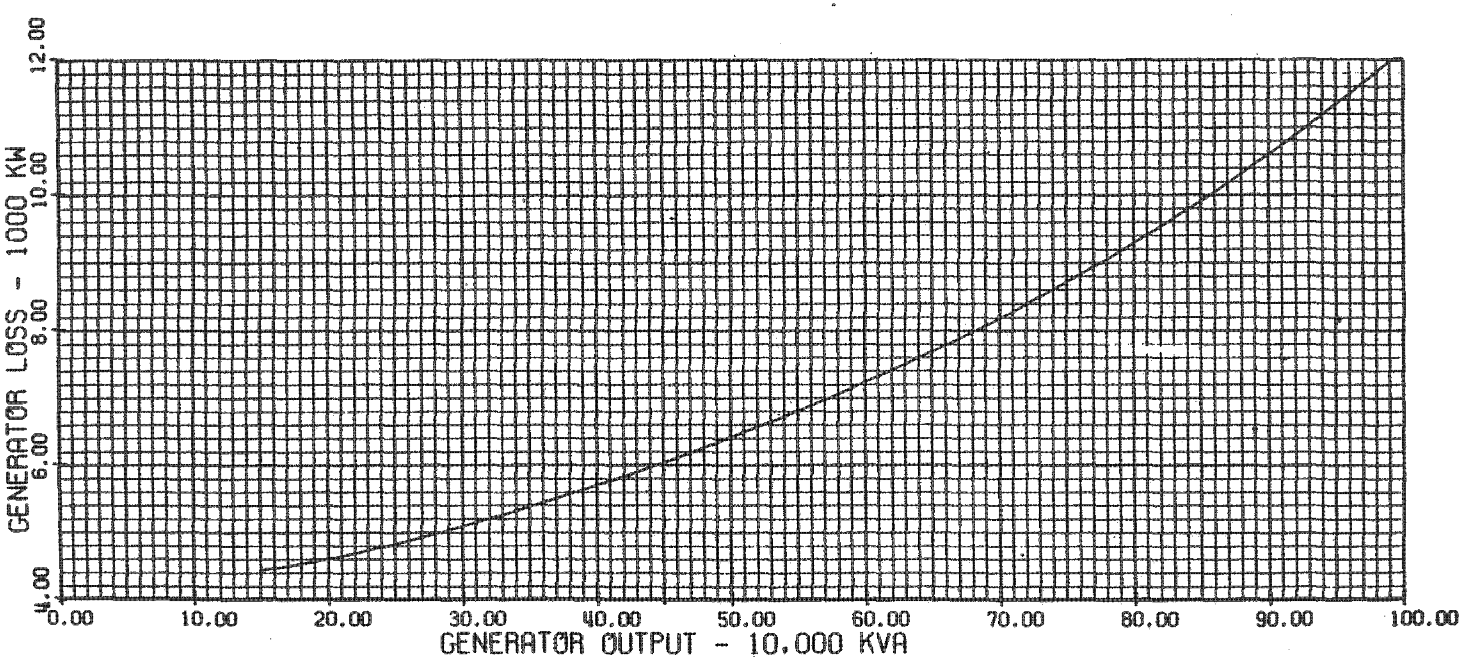
NOTES

GENERATOR LOSSES ASSUME RATED HYDROGEN PRESSURE AT ALL LOADS.

GENERATOR LOSS AT REDUCED HYDROGEN PRESSURE (P) = LOSS AT RATED HYDROGEN PRESSURE - 14.3 $(P_{RATED} - P)$. USE GENERATOR REACTIVE CAPABILITY CURVE TO DETERMINE GENERATOR CAPABILITY AT REDUCED HYDROGEN PRESSURE.

TURBINE GENERATOR MECHANICAL LOSSES ARE NOT INCLUDED IN THE GENERATOR LOSS CURVE.

IF HYDROGEN AND STATOR LIQUID COOLERS ARE LOCATED IN THE CONDENSATE LINE, THE LOSS TRANSFERRED TO THE COOLERS IS 898 KW LESS THAN THE GENERATOR LOSS AT ALL LOADS.

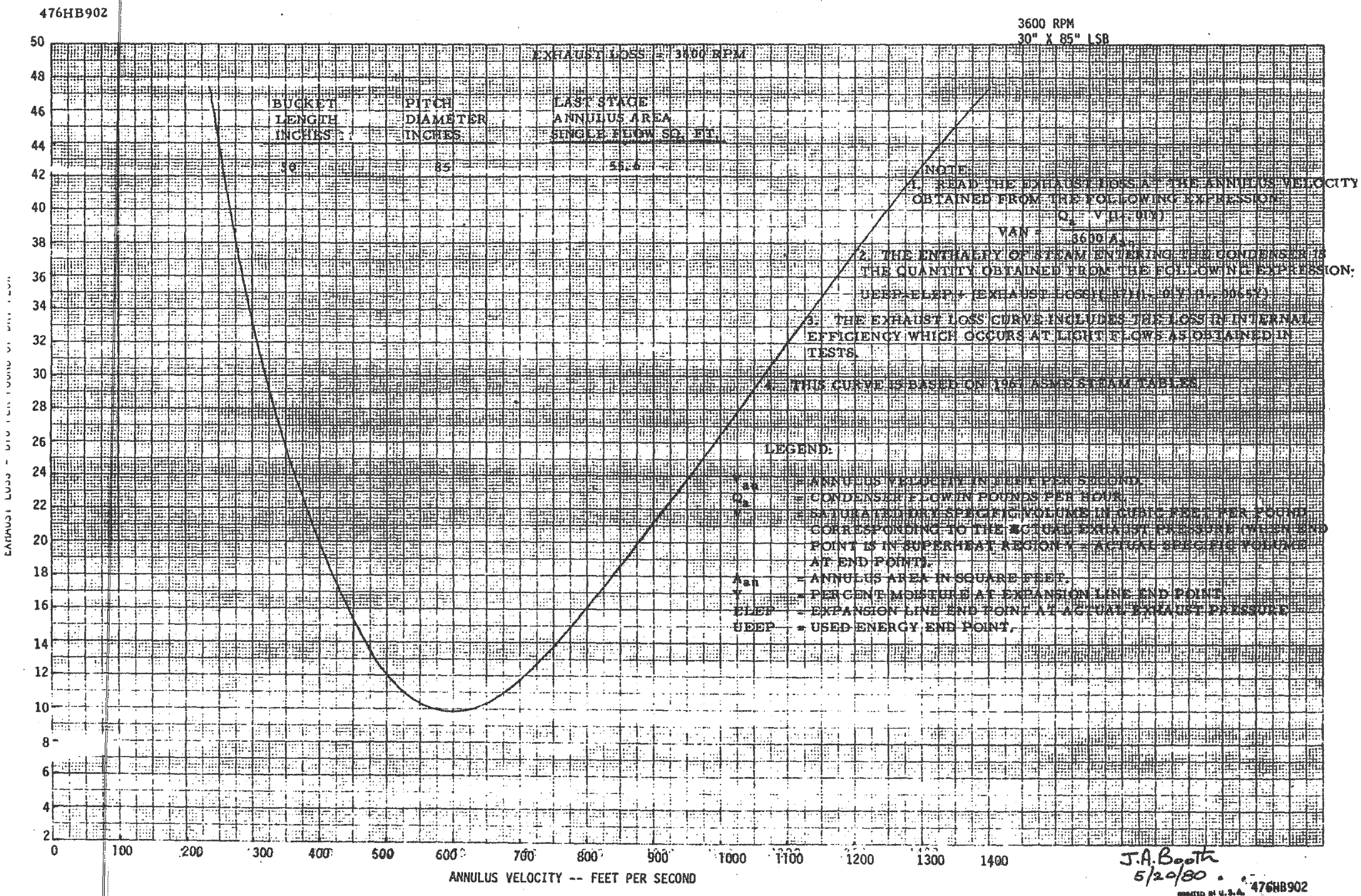



GENERAL ELECTRIC COMPANY, SCHENECTADY, NEW YORK

V. K. Major

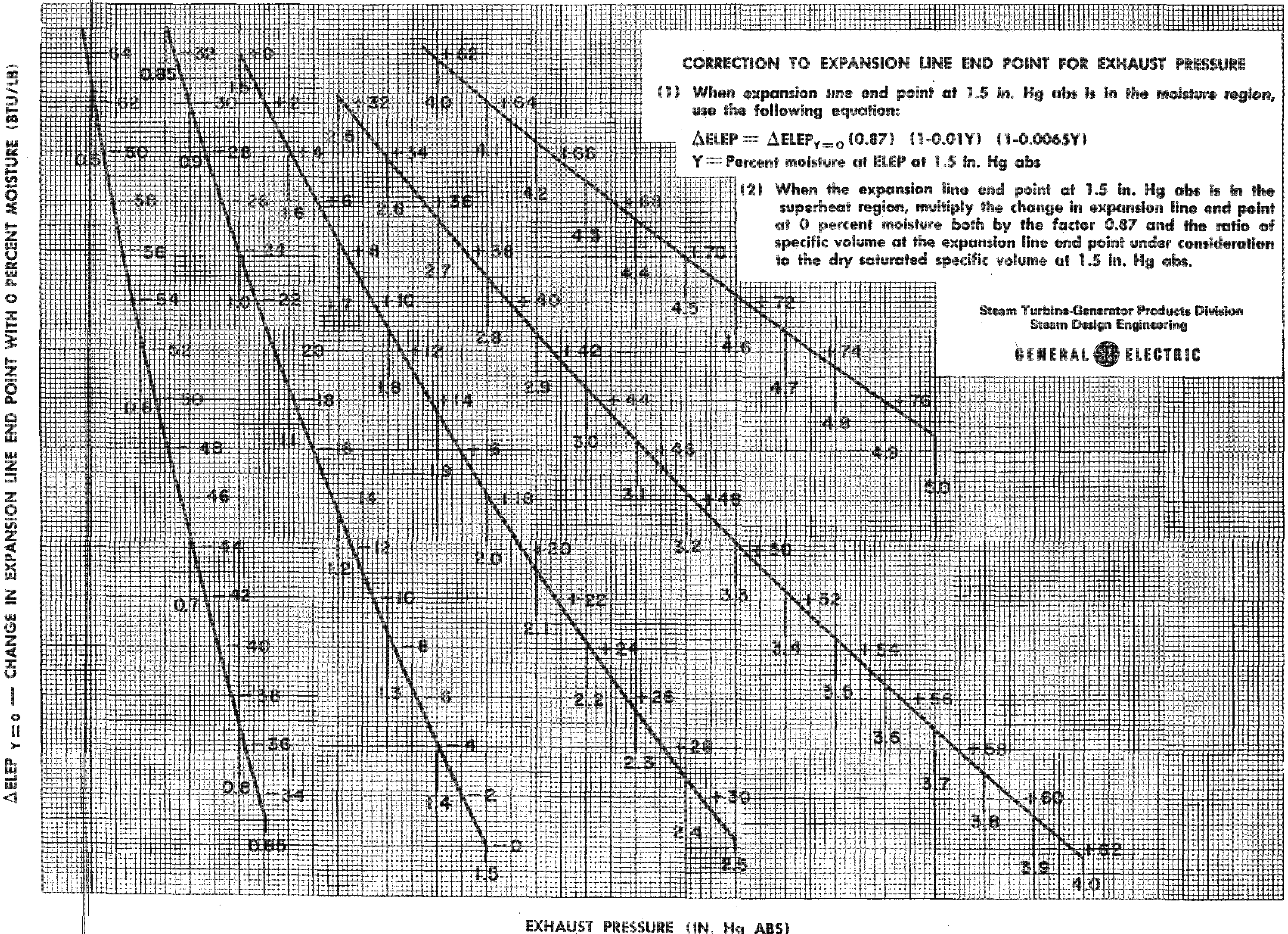
12/01/81

452 HB 891

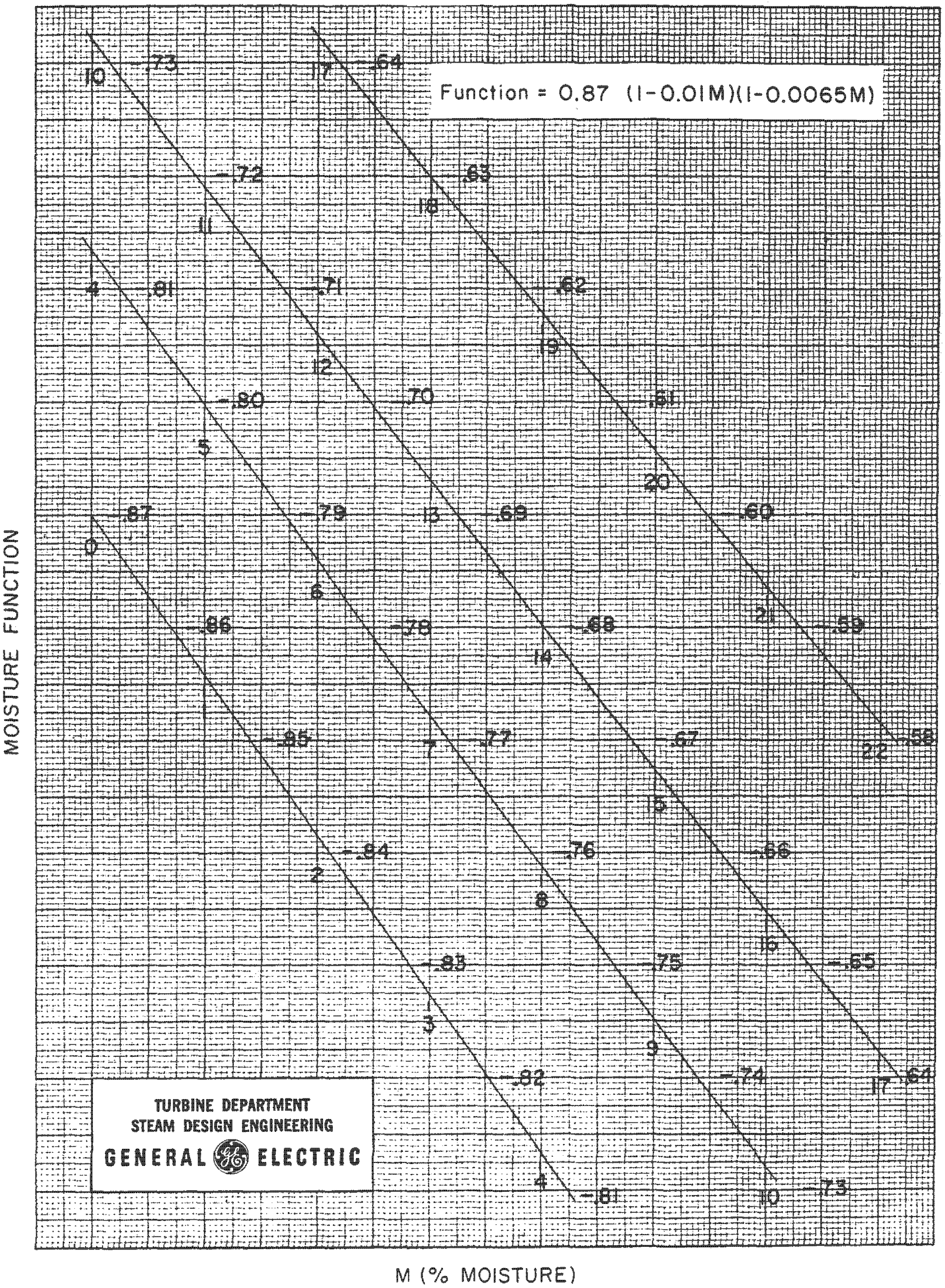

476HB902
3600 RPM
30" X 85" LSB
EXHAUST LOSS - 3600 RPM
BUCKET LENGTH INCHES
PITCH DIAMETER INCHES
LAST STAGE ANNULUS AREA SINGLE FLOW SQ. FT.
30
85
55.6
NOTE:
1. READ THE EXHAUST LOSS AT THE ANNULUS VELOCITY OBTAINED FROM THE FOLLOWING EXPRESSION:
VAN = Qa V (1-.01Y) / 3600 Aan
2. THE ENTHALPY OF STEAM ENTERING THE CONDENSER IS THE QUANTITY OBTAINED FROM THE FOLLOWING EXPRESSION:
3. THE EXHAUST LOSS CURVE INCLUDES THE LOSS IN INTERNAL EFFICIENCY WHICH OCCURS AT LIGHT FLOWS AS OBTAINED IN TESTS.
4. THIS CURVE IS BASED ON 1967 ASME STEAM TABLES.
LEGEND:
Van = ANNULUS VELOCITY IN FEET PER SECOND.
Qa = CONDENSER FLOW IN POUNDS PER HOUR.
Aan = ANNULUS AREA IN SQUARE FEET.
Y = PERCENT MOISTURE AT EXPANSION LINE END POINT.
ELEP = EXPANSION LINE END POINT AT ACTUAL EXHAUST PRESSURE
UEEP = USED ENERGY END POINT.
ANNULUS VELOCITY -- FEET PER SECOND
J.A. Booth
5/20/80
PRINTED IN U.S.A. 476HB902

IP14_007457

GEZ-3589A
5–75 (2M)



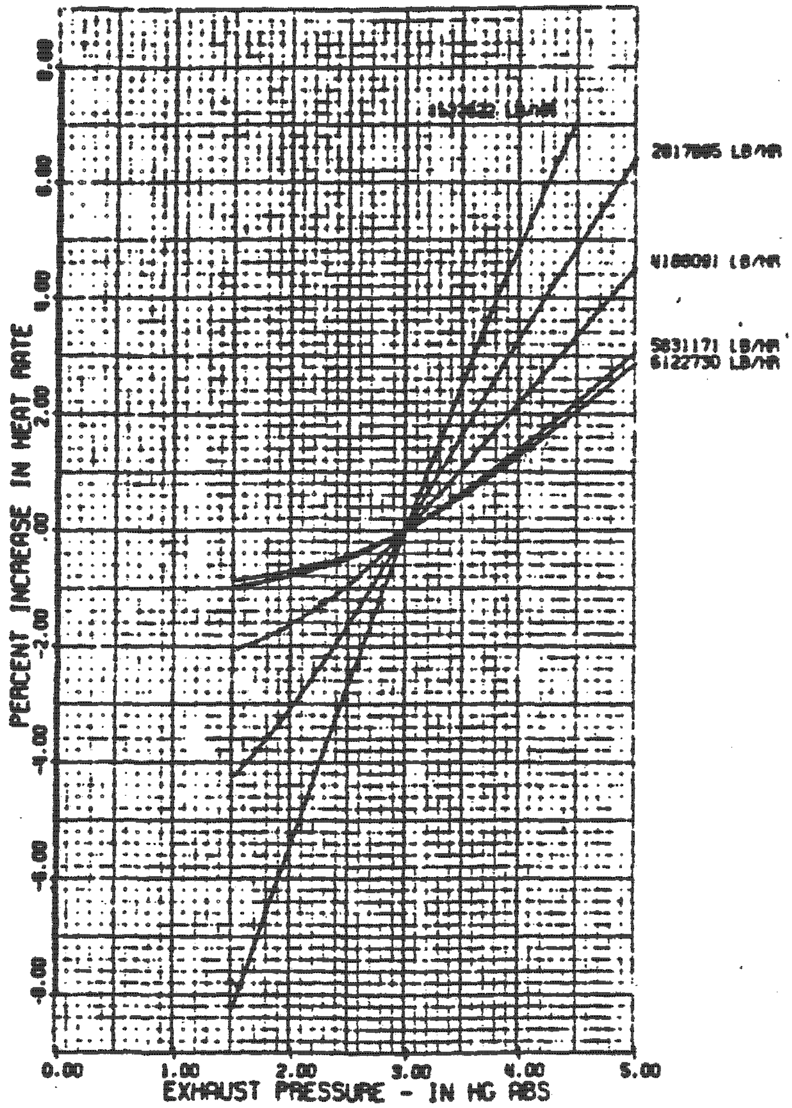

IP14_007458


Function = 0.87 (1-0.01M)(1-0.0065M)
MOISTURE FUNCTION
M (% MOISTURE)
TURBINE DEPARTMENT
STEAM DESIGN ENGINEERING
GENERAL ELECTRIC

# EXHAUST PRESSURE CORRECTION FACTORS

481 HB 475

820000 KW AT 1.66/ 2.24/ 2.99 IN HG ABS 1.00 PCT MU
TCGF-30.0 IN LSB 3600 RPM
2400 PSIA 1000/1000 T




METHOD OF USING CURVE

VALUES NEAR CURVES ARE FLOWS AT 2400 PSIA 1000 T
THESE CORRECTION FACTORS ASSUME CONSTANT CONTROL VALVE OPENING
APPLY CORRECTIONS TO HEAT RATE AND KW LOADS
AT 2.99/ 2.24/ 1.66 IN HG ABS AND 0.0 PCT MU.

THE PERCENT CHANGE IN KW LOAD FOR VARIOUS EXHAUST PRESSURES IS EQUAL TO
(MINUS PCT INCREASE IN HEAT RATE)100/(100 + PCT INCREASE IN HEAT RATE)

THESE CORRECTION FACTORS ARE NOT GUARANTEED

PRESSURES ALONG ABSCISSA ARE PRESSURES IN HOOD A

| PRESSURE (IN HG ABS) FOR HOOD A | HOOD B | HOOD C |
|---|---|---|
| 1.50 | 1.09 | .78 |
| 2.00 | 1.47 | 1.07 |
| 2.50 | 1.85 | 1.36 |
| 3.00 | 2.24 | 1.66 |
| 3.50 | 2.63 | 1.96 |
| 4.00 | 3.03 | 2.27 |
| 4.50 | 3.42 | 2.58 |
| 5.00 | 3.82 | 2.89 |

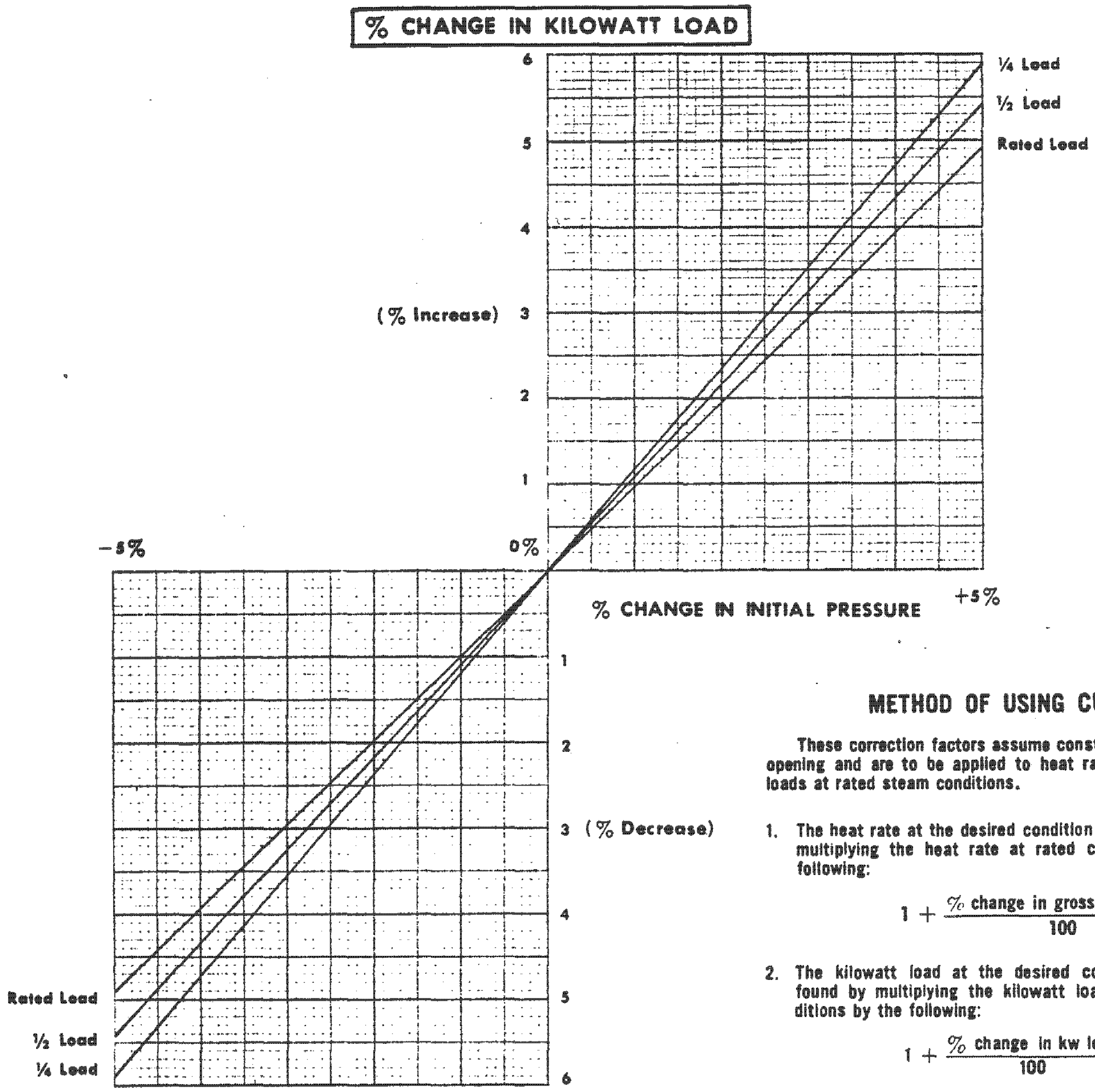
481 HB 475

GENERAL ELECTRIC COMPANY. SCHENECTADY. NEW YORK 12/04/81

3/26/84 Rev.1

# INITIAL PRESSURE CORRECTION FACTORS

## FOR SINGLE REHEAT UNITS




### METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

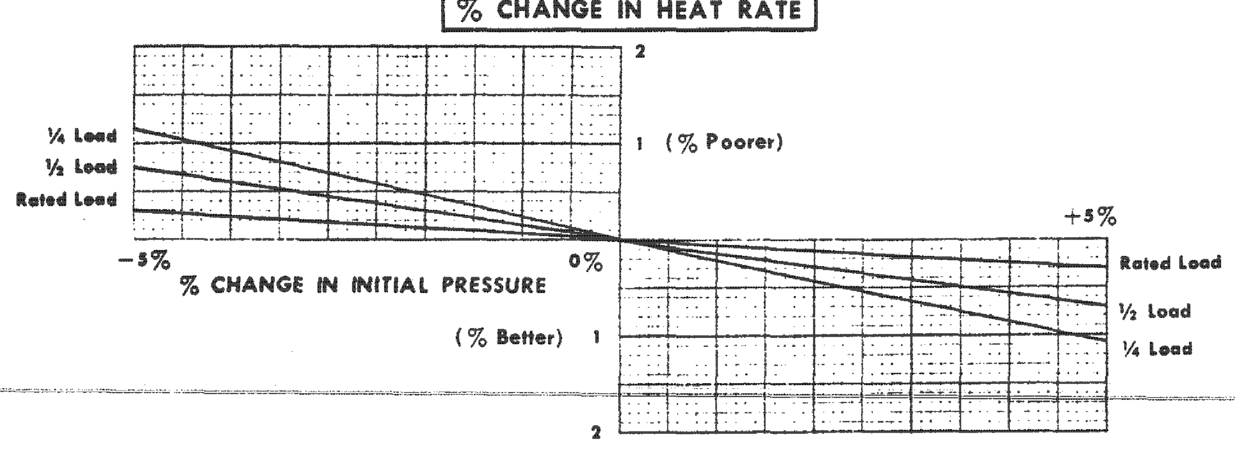
1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

$$1 + \frac{\text{\% change in gross heat rate}}{100}$$

2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

$$1 + \frac{\text{\% change in kw load}}{100}$$

3. These correction factors are not guaranteed.




GEZ-3614

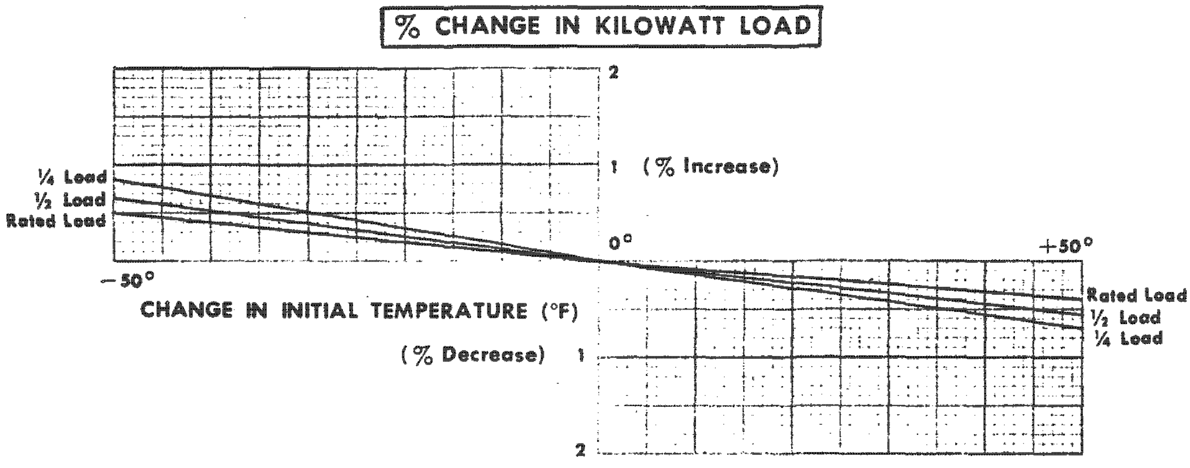
4-81 (2M)

GENERAL ELECTRIC

IP14_007461

# INITIAL TEMPERATURE CORRECTION FACTORS

## FOR SINGLE REHEAT—SUBCRITICAL PRESSURE UNITS




### METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

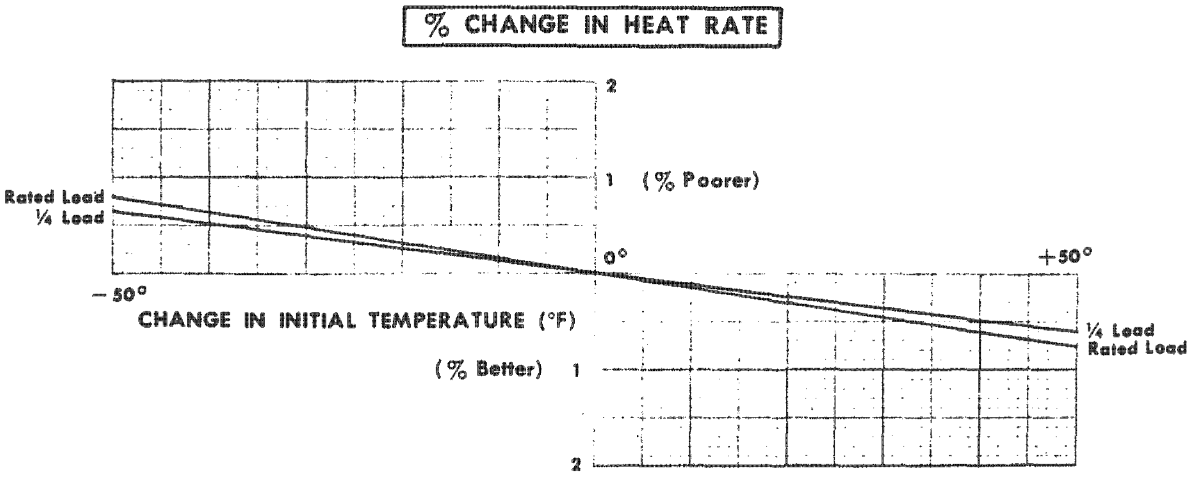
1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

$$1 + \frac{\%\text{ change in gross heat rate}}{100}$$

2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

$$1 + \frac{\%\text{ change in kw load}}{100}$$

3. These correction factors are not guaranteed.

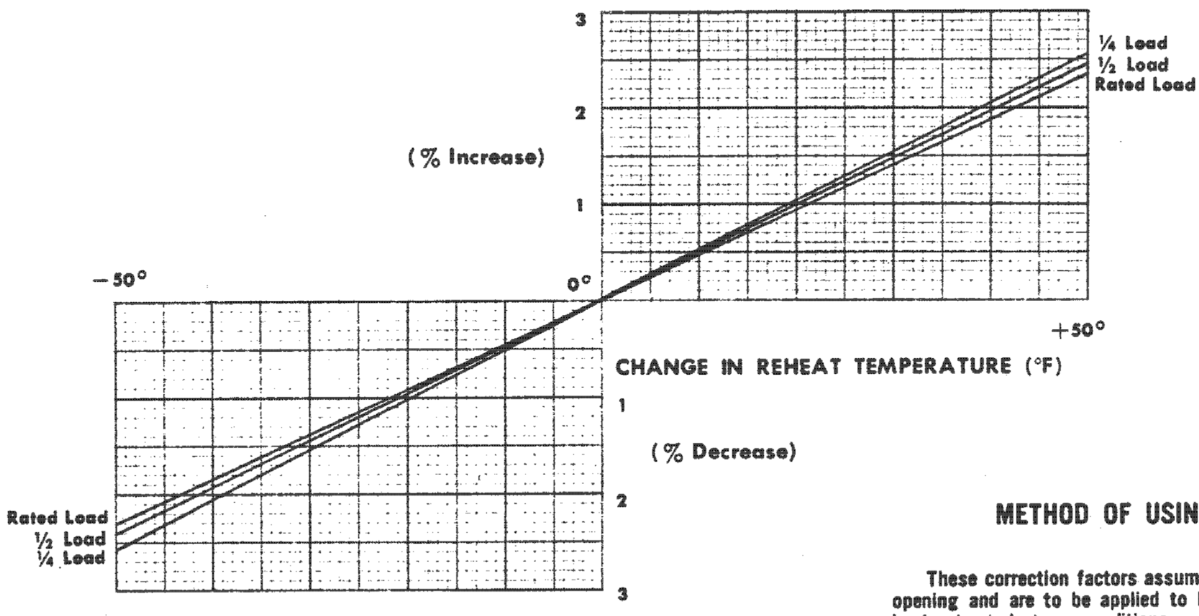



GEZ-3615
3–79 (2M)

GENERAL ELECTRIC
PRINTED IN U.S.A.

# REHEAT TEMPERATURE CORRECTION FACTORS
## FOR SINGLE REHEAT UNITS

**% CHANGE IN KILOWATT LOAD**




### METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

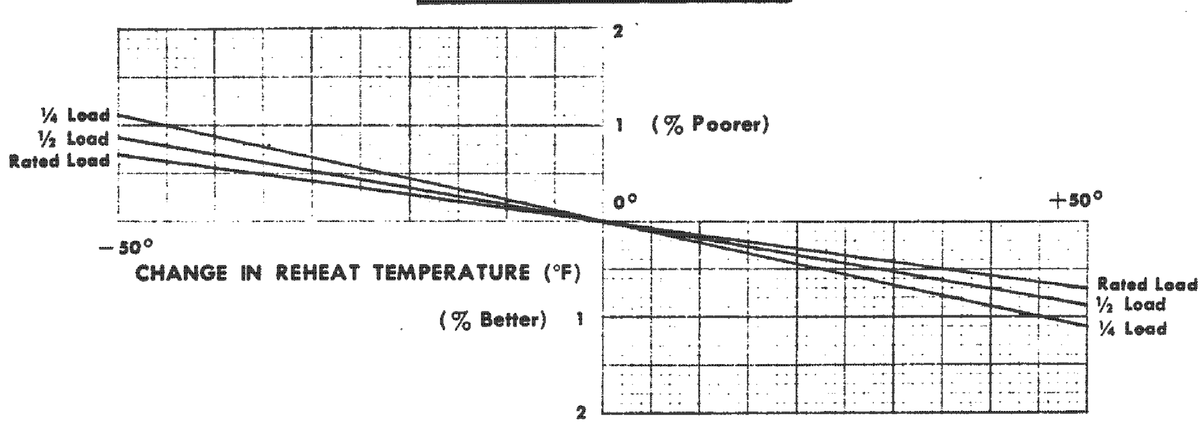
$$1 + \frac{\%\text{ change in gross heat rate}}{100}$$

2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

$$1 + \frac{\%\text{ change in kw load}}{100}$$

3. These correction factors are not guaranteed.

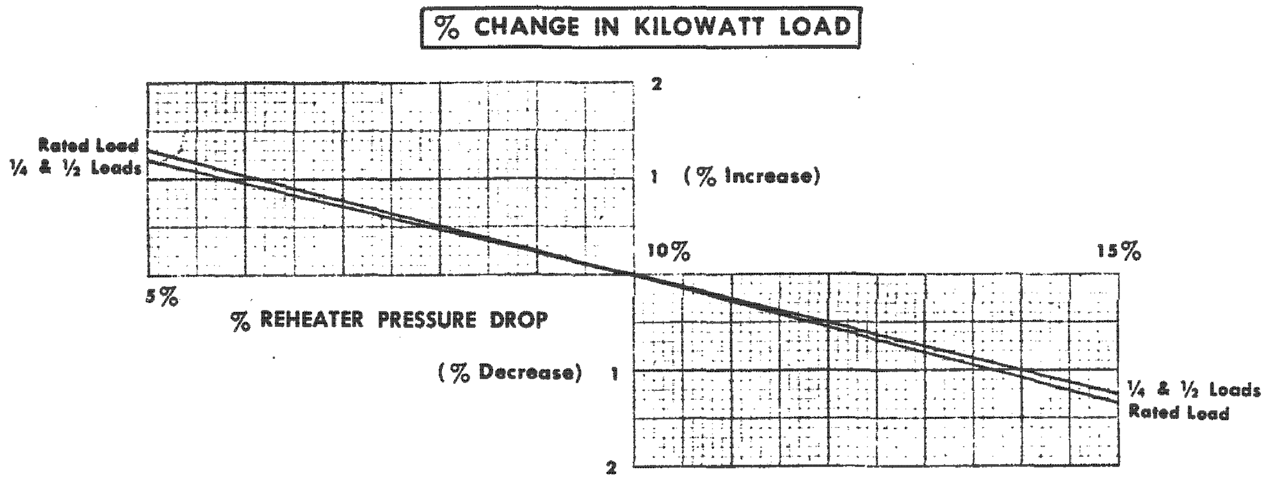
**% CHANGE IN HEAT RATE**




GEZ-3617
6–75 (2500)

GENERAL ELECTRIC

# REHEATER PRESSURE DROP CORRECTION FACTORS
## FOR SINGLE REHEAT UNITS




### METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

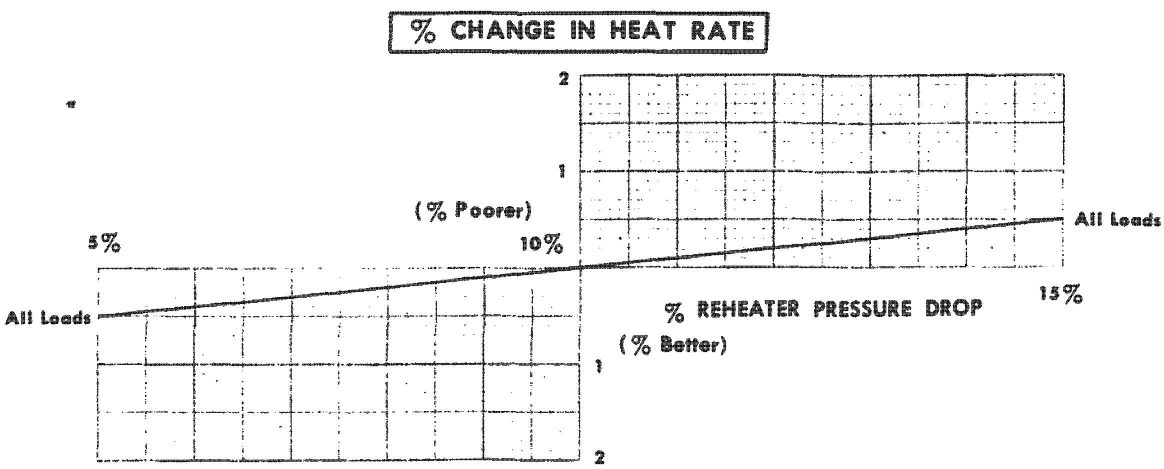
1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

$$1 + \frac{\%\ \text{change in gross heat rate}}{100}$$

2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

$$1 + \frac{\%\ \text{change in kw load}}{100}$$

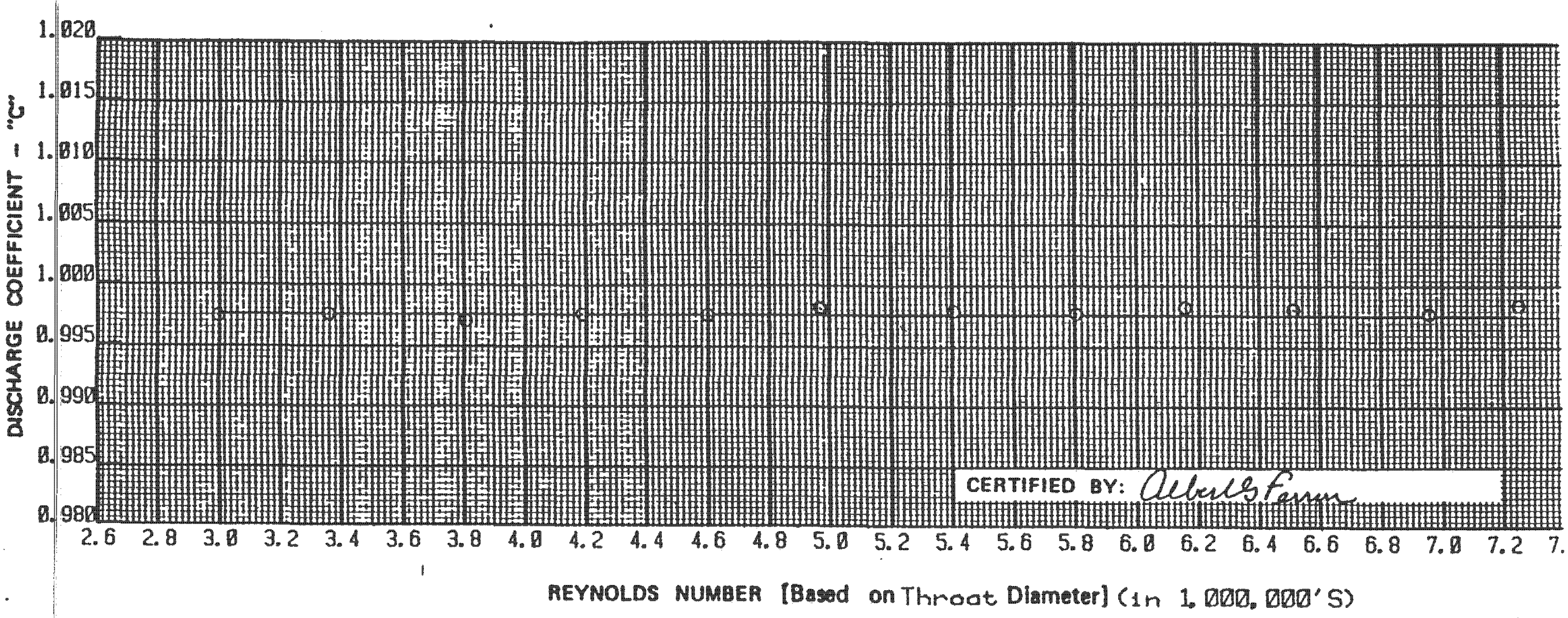
3. These correction factors are not guaranteed.




GEZ-3618
6–75 (2500)

GENERAL ELECTRIC

IP14_007464



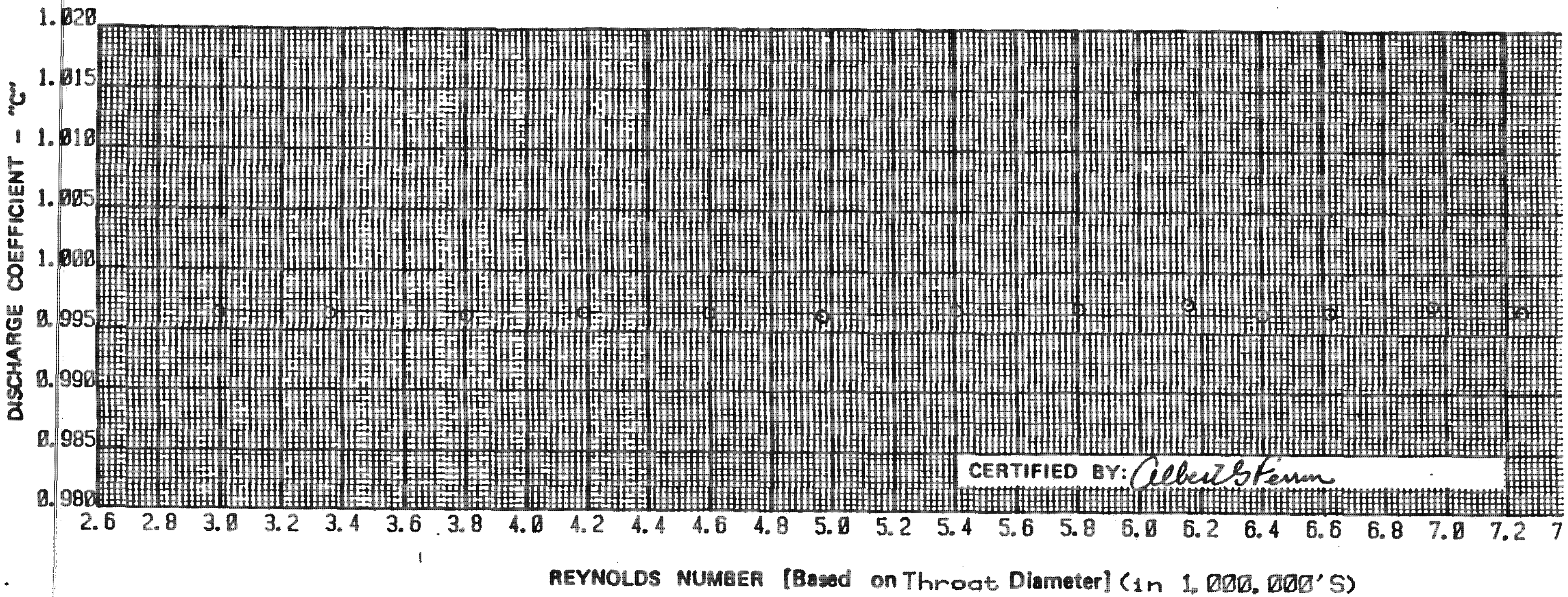

$$q_a = C \; K_M \sqrt{h}$$

| | |
|---|---|
| $q_a$ = Actual Flow Rate (ft$^3$/sec) | |
| C = Discharge Coefficient — Dimensionless | |
| h = Pressure Differential in Feet of Water at Run Temperature | |
| $K_M$ = Meter Constant = $\dfrac{a\sqrt{2g} \times F_a}{\sqrt{1 - \beta^4}}$ = | 4.3092 |
| $F_a$ = Thermal Expansion Factor = | 1.0005 |
| a = Throat Area (ft$^2$) = | 0.5283 |
| g = Local Acceleration of Gravity (ft/sec$^2$) | 32.163 |
| $\beta$ = Dimensionless Ratio of Throat to Pipe Diameter = | 0.4233 |
| Upstream Diameter = | 23.250 |
| Throat Diameter = | 9.842 |
| Dimensions By: DANIEL | |

MEAN - 0.9977 ABOVE THROAT
REYNOLDS # 2900000

TAP SET # A
24" FLOW NOZZLE ASSEMBLY
TAG NUMBER: 9 FWCF51-FE-0010
DANIEL INDUSTRIES, INC.
PO NUMBER: 77256
OCTOBER 1, 1984

IP14_007465



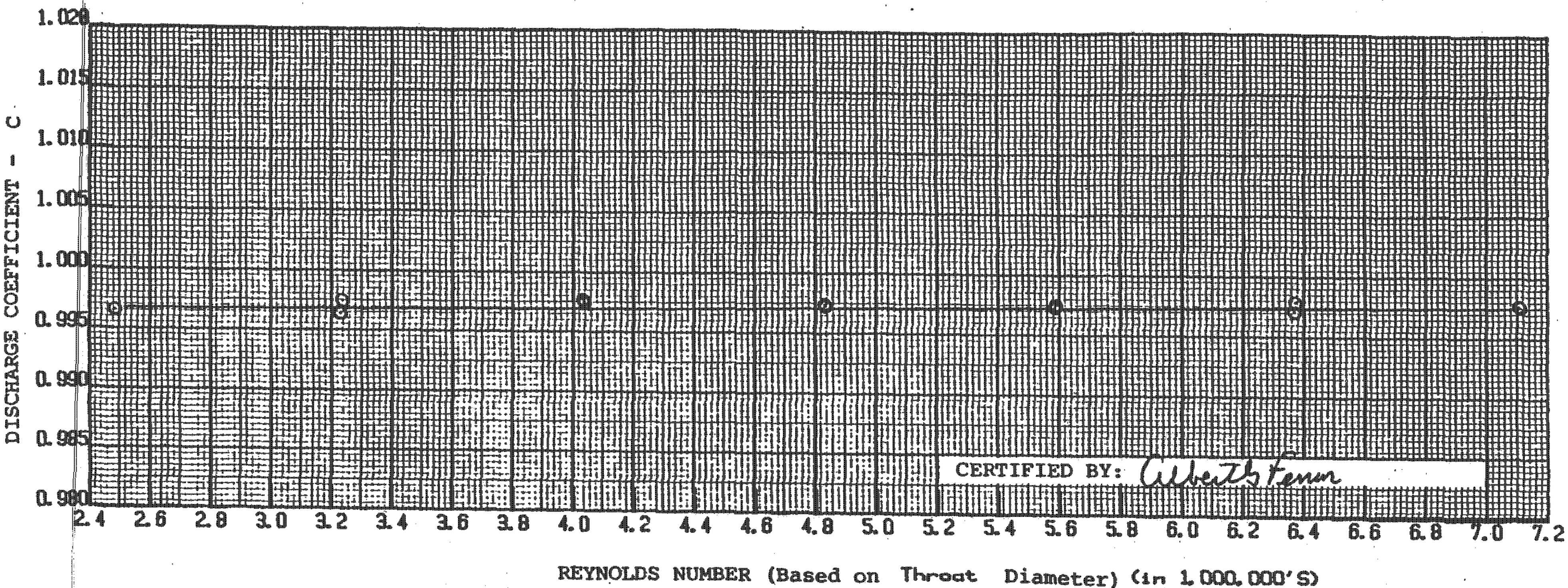

$$q_a = C \ K_M \sqrt{h}$$

| | |
|---|---|
| $q_a$ = Actual Flow Rate ($ft^3$/sec) | |
| C = Discharge Coefficient — Dimensionless | |
| h = Pressure Differential in Feet of Water at Run Temperature | |
| $K_M$ = Meter Constant = $\dfrac{a\sqrt{2g} \times F_a}{\sqrt{1-\beta^4}}$ = | 4.3092 |
| $F_a$ = Thermal Expansion Factor = | 1.0005 |
| a = Throat Area ($ft^2$) = | 0.5283 |
| g = Local Acceleration of Gravity (ft/$sec^2$) | 32.163 |
| $\beta$ = Dimensionless Ratio of Throat to Pipe Diameter = | 0.4233 |
| Upstream Diameter = | 23.250 |
| Throat Diameter = | 9.842 |
| Dimensions By: DANIEL | |

MEAN - 0.9965 ABOVE THROAT
REYNOLDS # 2800000

TAP SET # B
24" FLOW NOZZLE ASSEMBLY
TAG NUMBER: .9 FWCF51-FE-0010
DANIEL INDUSTRIES, INC.
PO NUMBER: 77256
OCTOBER 1, 1984

IP14_007466



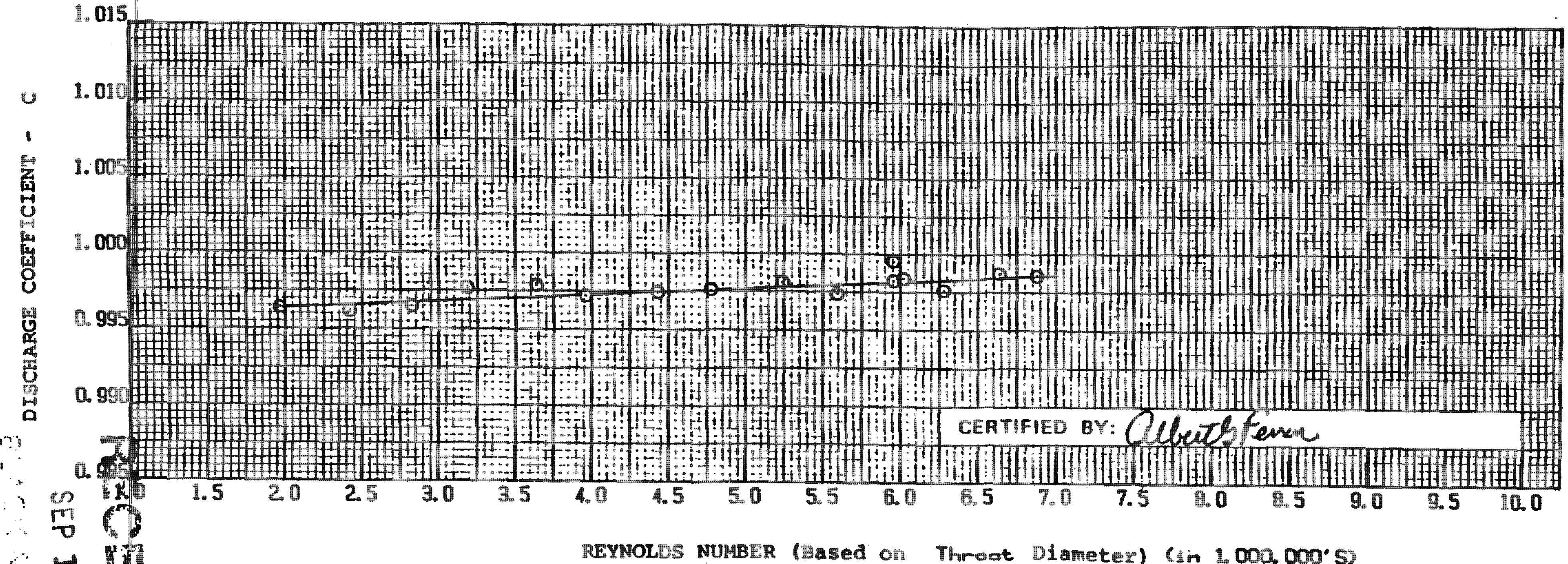

$$q_a = C\ K_M \sqrt{h}$$

| | |
|---|---|
| $q_a$ = Actual Flow Rate ($ft^3$/sec) | |
| C = Discharge Coefficient - Dimensionless | |
| h = Pressure Differential in Feet of Water at Run Temperature | |
| $K_M$ = Meter Constant = $\dfrac{a\sqrt{2g} \times F_a}{\sqrt{1 - \beta^4}}$ = | 2.7432 |
| $F_a$ = Thermal Expansion Factor = | 1.0006 |
| a = Throat Area ($ft^2$) = | 0.3323 |
| g = Local Acceleration of Gravity (ft/$sec^2$) | 32.163 |
| β = Dimensionless Ratio of Throat to Pipe Diameter = | 0.4836 |
| Upstream Diameter = | 16.142 |
| Throat Diameter = | 7.8060 |
| Dimensions By: B.I.F. | |

TAP SET # 1
20" PTC-6 TEST SECTION
SERIAL NUMBER: C90916-1
B.I.F.
PO NUMBER: 85797-KO
SEPTEMBER 16, 1985

ARL

IP14_007467



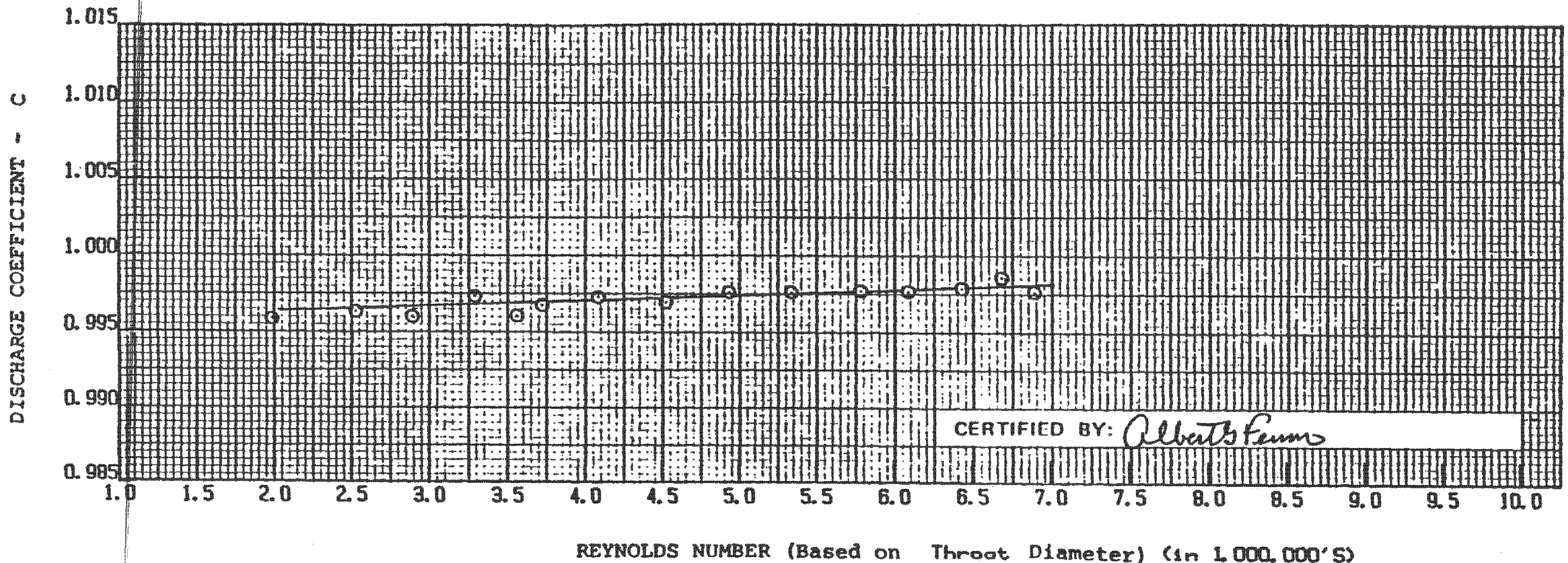



$$q_a = C\,K_M\sqrt{h}$$

| | |
|---|---|
| $q_a$ = Actual Flow Rate ($ft^3/sec$) | |
| C = Discharge Coefficient - Dimensionless | |
| h = Pressure Differential in Feet of Water at Run Temperature | |
| $K_M$ = Meter Constant = $\dfrac{a\sqrt{2g} \times F_a}{\sqrt{1-\beta^4}}$ = | 2.7262 |
| $F_a$ = Thermal Expansion Factor = | 1.0008 |
| a = Throat Area ($ft^2$) = | 0.3325 |
| g = Local Acceleration of Gravity ($ft/sec^2$) | 32.163 |
| β = Dimensionless Ratio of Throat to Pipe Diameter = | 0.4525 |
| Upstream Diameter = | 17.254 |
| Throat Diameter = | 7.8080 |
| Dimensions By: DANIEL | |

TAP SET # A
18" FLOW NOZZLE ASSEMBLY
SERIAL NUMBER: 85-110134
DANIEL INDUSTRIES INCORPORATED
PO NUMBER: 1-PO-81459
MAY 15, 1985

ARL




| $q_a = C\,K_M\sqrt{h}$ | |
|---|---|
| $q_a$ = Actual Flow Rate ($ft^3$/sec) | |
| C = Discharge Coefficient - Dimensionless | |
| h = Pressure Differential in Feet of Water at Run Temperature | |
| $K_M$ = Meter Constant = $\dfrac{a\sqrt{2g} \times F_a}{\sqrt{1-\beta^4}}$ = | 2.7255 |
| $F_a$ = Thermal Expansion Factor = | 1.0008 |
| a = Throat Area ($ft^2$) = | 0.3324 |
| g = Local Acceleration of Gravity (ft/$sec^2$) | 32.163 |
| β = Dimensionless Ratio of Throat to Pipe Diameter = | 0.4523 |
| Upstream Diameter = | 17.259 |
| Throat Diameter = | 7.8070 |
| Dimensions By: DANIEL | |

TAP SET # A

18" FLOW NOZZLE ASSEMBLY

SERIAL NUMBER: 85-110135

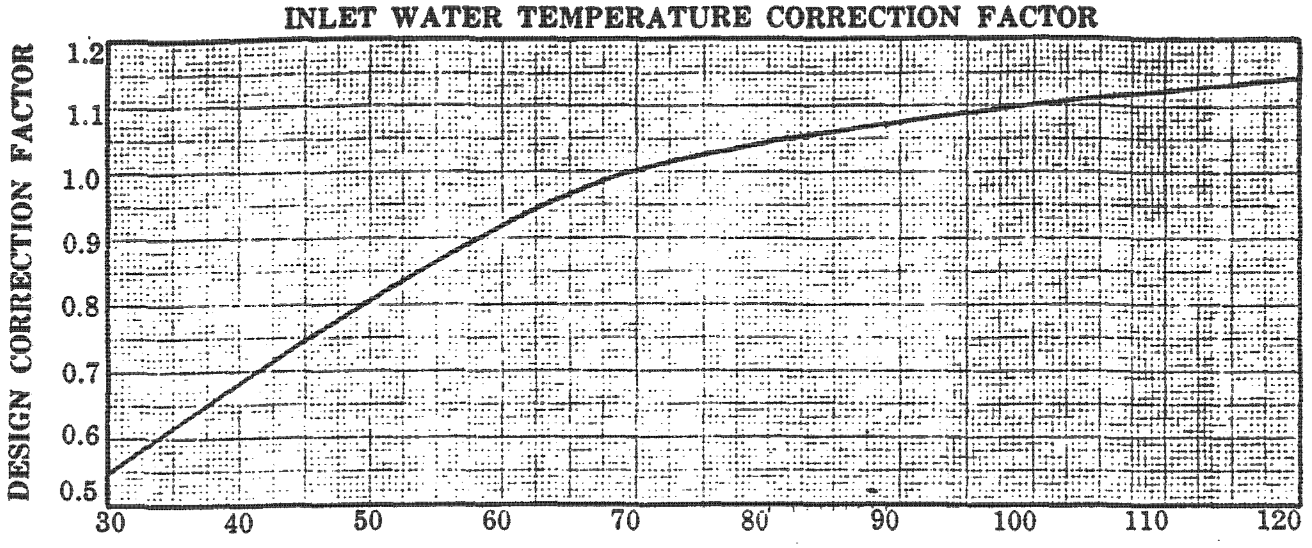
DANIEL INDUSTRIES INCORPORATED

PO NUMBER: 1-PO-81459

MAY 15, 1985

ARL

IP14_007469




TEMPERATURE OF INLET WATER DEGREES F

Fig. 2